FOCUS ENERGY TRUST

Annual Report

2003

Notice of Annual General Meeting

The Annual General Meeting of Unitholders will be held at 3:00 p.m. on Thursday, May 27, 2004 in the Lakeview room at the Westin Hotel, 320 – 4th Avenue SW, Calgary, Alberta.

All Unitholders are invited to attend.

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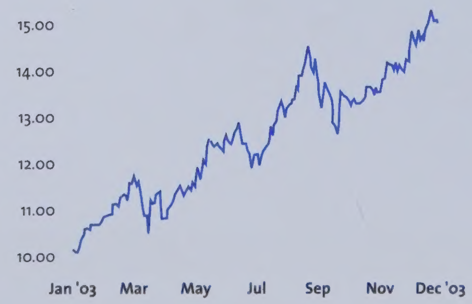
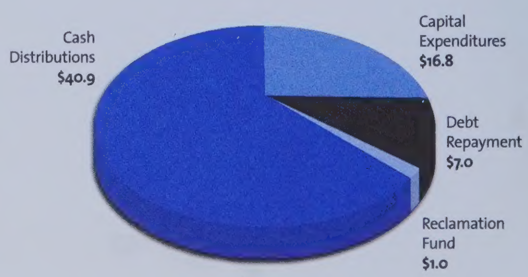
Focus Energy Trust (FET.UN-T)
2003 (Can$)



Funds Flow from Operations (millions)



Forward-Looking Information

Certain information set forth in this document, including management's assessment of Focus' future plans and operations, contains forward-looking statements. By their nature, forward-looking statements are subject to numerous risks and uncertainties, some of which are beyond Focus' control, including the impact of general economic conditions, industry conditions, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other industry participants, the lack of availability of qualified personnel or management, stock market volatility and ability to access sufficient capital from internal and external sources. Readers are cautioned that the assumptions used in the preparation of such information, although considered reasonable at the time of preparation, may prove to be imprecise and, as such, undue reliance should not be placed on forward-looking statements. Focus' actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking statements and, accordingly, no assurance can be given that any of the events anticipated by the forward-looking statements will transpire or occur, or if any of them do so, what benefits that Focus will derive therefrom. Focus disclaims any intention or obligation to update or revise any forward-looking statements. whether as a result of new information, future events or otherwise. Readers are cautioned that net present value of reserves does not represent fair market value of reserves.

Corporate Profile

Focus Energy Trust is a natural gas weighted energy trust. Focus is committed to maintaining its emphasis on operating high quality oil and gas properties, delivering consistent distributions to Unitholders, and ensuring financial strength and sustainability.

Focus produces approximately 10,000 BOE per day of natural gas and light oil from five main areas in British Columbia and Alberta. Production is weighted 73 percent to natural gas, and approximately 87 percent of production is operated by Focus.

Focus Energy Trust Units trade on the TSX under the symbol FET.UN, and the Exchangeable Shares of FET Resources Ltd. trade on the TSX under the symbol FTX.

2003 Highlights

(thousands of dollars, except where indicated)		Years Ended, December 31, 2003		2002 (1)
FINANCIAL				
Oil and gas revenues, before royalties		111,832		114,594
Funds flow from operations (2)		65,808		55,455
Per unit (3)	$	2.16	$	1.97
Per BOE	$	21.09	$	14.17
Cash distributions		40,926		7,250
Per unit (4)	$	1.665	$	0.44
Payout ratio (per unit basis)		77%		n/a
Net income		41,472		19,205
Per unit (3)	$	1.36	$	0.68
Capital expenditures		16,809		40,140
Per unit (3)	$	0.55	$	1.42
Acquisitions, net of proceeds on disposition		20,216		–
Net debt (long-term debt plus working capital)		24,641		36,534
Per unit	$	0.77	$	1.26
Net debt to funds flow		0.4		0.7
Total Trust Units - outstanding (000's) (5)		31,822		28,966
Weighted average Total Trust Units (000's) (6)		30,493		28,210
OPERATIONS				
Average daily production				
Crude oil (bbls/d)		2,354		4,831
NGLs (bbls/d)		485		502
Natural gas (mcf/d)		34,254		32,316
Barrels of oil equivalent (BOE/d @ 6:1)		8,548		10,719
Average product prices realized (7)				
Crude oil ($CDN/bbl)	$	40.74	$	38.11
NGLs ($CDN/bbl)	$	34.24	$	29.15
Natural gas ($CDN/mcf)	$	5.55	$	3.67
Netback per BOE				
Revenue (7)	$	35.41	$	29.64
Royalties, net of ARTC	$	(9.78)	$	(7.08)
Production expenses	$	(3.39)	$	(3.32)
Netback per BOE	$	22.24	$	19.24
Wells drilled				
Gross		23		38
Net		9.3		25.5
Success rate		96%		74%

	Years Ended, December 31, 2003	2002
TRUST UNIT TRADING STATISTICS		
Unit prices (based on daily closing price)		
High	$ 15.30	$ 10.65
Low	$ 10.05	$ 9.40
Close	$ 15.00	$ 10.15
Daily average trading volume	87,848	178,081
RESERVES		
Proven plus Probable (8)		
Crude oil (Mbbls)	6,498	5,531
NGLs (Mbbls)	2,037	1,893
Natural gas (Mmcf)	126,360	122,534
Barrels of oil equivalent (Mboe @ 6:1)	29,595	27,846
Reserve life index, proven plus probable (9)	9.8	9.1
Gas weighting of proven plus probable reserves	71%	73%
Proven reserves / proven plus probable reserves	77%	88%

(1) Focus is the successor organization to Storm Energy Inc. and comparative information for the year ended December 31, 2002 includes the operations of Storm Energy Inc. for the period January 1, 2002 to August 23, 2002 prior to the reorganization.

(2) Funds flow from operations ("funds flow" before changes in non-cash working capital) is used by management to analyze operating performance and leverage. Funds flow as presented does not have any standardized meaning prescribed by Canadian GAPP and therefore it may not be comparable with the calculation of similar measures of other entities. Funds flow as presented is not intended to represent operating cash flow or operating profits for the period nor should it be viewed as an alternative to cash flow from operating activities, net earnings or other measures of financial performance calculated in accordance with Canadian GAPP. All references to funds flow throughout this report are based on funds flow from operations before changes in non-cash working capital.

(3) Based on weighted average Total Trust Units outstanding for the year.

(4) Based on the number of Trust Units outstanding at each cash distribution date.

(5) Total Trust Units being Trust Units and Exchangeable Shares converted at the exchange ratio prevailing at the time. The exchange ratio was 1.16718 at December 31, 2003 and 1.03291 at December 31, 2002.

(6) Total Trust Units being Trust Units and Exchangeable Shares converted at average exchange ratio.

(7) Including settlements for financial instruments, and excludes hedging gains or losses calculated on a mark-to-market basis.

(8) Reserve numbers for 2003 are based on total proved plus probable company working interest reserves before deduction of royalties and without including any royalty interests as defined in National Instrument 51-101 ("NI 51-101"). Reserve numbers for 2002 are based on established (proved plus 50 percent probable) company working interest reserves before deduction of royalties and without including any royalty interests.

(9) Reserve life index for December 31, 2003 is calculated by dividing year-end reserves by the 2004 production estimate from the reserve reports. The reserve life index for December 31, 2002 was calculated by dividing year-end reserves by 2002 fourth quarter production.

Message to the Unitholders

Focus completed its first full year of operations as a trust in 2003. Performance in 2003 reflects the strong commodity price environment, the quality of our assets and the execution of our business strategy. Focus' strategy is to surface value on our existing assets, maintain our cost efficiencies, maintain financial strength, acquire quality assets and assemble & retain the best value creation team in the business.

In 2003 we were able to maintain the Trust's production through the reinvestment of 25 percent of cash flow on internal development opportunities at our key properties.

Highlights

- Focus Unitholders realized a 63 percent total return in 2003. This performance places Focus as one of the top performing trusts in its sector.
- Focus maintained stable monthly distributions of $0.14 per Unit for the final three quarters of 2003. The Trust's payout ratio was 77 percent on a per unit basis.
- We reinvested $16.8 million (25 percent of cash flow) on internally generated opportunities and acquired $20.2 million of new assets.
- Based on Proven plus Probable reserves our capital program replaced 156 percent of our annual production.
- Proven plus Probable reserves at December 31, 2003 increased by 6 percent over Established reserves at December 31, 2002.
- Finding, Development and Acquisition costs of $7.88 per BOE (including development capital) are among the lowest in the trust sector.
- Our asset base at year-end 2003 has a Proven plus Probable reserve life index of 9.8 years with a natural gas weighting of 71 percent.
- Operating costs of $3.39/BOE are among the lowest in the trust sector.
- We maintained our financial flexibility and "dry powder" with a conservative debt to cash flow ratio of 0.4 times.

Sustainability

When Focus was created in August of 2002, we set out to create a sustainable trust. A trust that placed greater emphasis on utilizing internal development opportunities to maintain production volumes and used acquisition opportunities selectively to provide for strategic growth. Our model indicated that with the right assets and 25 percent of cash flow we should be capable of sustaining production.

In 2003 we have been successful in that regard. Utilizing our large inventory of internal development opportunities we were able to sustain our production with 25 percent of cash flow, with the remaining 75 percent being distributed to our Unitholders. Acquisitions in 2003 were funded with new units and were strategic in nature, typically not being material in terms of the production volumes, but very significant in terms of the internal development opportunities added to the Trust's inventory. Based on our current inventory of development opportunities we are confident that by reinvesting 25 percent of cash flow we will be able to maintain production again in 2004.

Subsequent Events

On April 1, 2004, Focus acquired additional working interests at its Tommy Lakes property in northeastern British Columbia for $110 million. The acquisition was financed with a combination of debt drawn from Focus' existing credit facilities and bought-deal financing of $74.5 million. The interests acquired had average production per day for January and February 2004 of approximately 11.7 mmcf per day of natural gas and 250 barrels per day of natural gas liquids. Total proved and probable reserves for the property are 11.7 million barrels of oil equivalent, being 62.4 bcf of natural

gas and 1.3 million barrels of natural gas liquids. Proven reserves represent 76.5 percent of total proved and probable reserves. Reserves are based on an independent engineering evaluation conducted by Paddock Lindstrom & Associates Ltd. effective April 1, 2004 and prepared in accordance with National Instrument 51-101. The acquisition represents 20,060 gross acres of undeveloped land (11,040 net acres), and the associated ownership in natural gas gathering and processing facilities. This acquisition provides accretion on cash flow, net asset value, production per Unit and proved reserves per Unit.

On April 15th, 2004 Focus increased it's distribution to $0.15 per Unit for the second quarter of 2004 due in large part to the accretive nature of the Tommy Lakes acquisition.

Outlook

In 2004 we plan to spend approximately $20.6 million on the further development of our asset base. Development activities will continue in all our core areas with the majority of our development dollars being spent at Tommy Lakes, Loon Lake and Pouce Coupe. We expect that these internal development opportunities combined with the Tommy Lakes acquisition will result in average production of 10,000 BOE per day in 2004.

The acquisition market continues to provide challenges from both a quality and cost perspective. It is expected that competition for quality assets will remain high in 2004. We continue to assess both property and corporate opportunities, and are well positioned to undertake an acquisition of material size if, and when, an opportunity meets our criteria.

Our inventory of internal development opportunities on our existing assets allows us to maintain our production at a constant level without having to access the acquisition market. This internal inventory of opportunities allows us to be patient and disciplined in our assessment of all acquisition opportunities.

Commodity prices and the Canadian/US dollar exchange rate will continue to be volatile in 2004 as they were in 2003. We will continue to manage our distribution profile through our price protection program and a conservative distribution policy that will ultimately enhance the long-term returns to Unitholders.

We sincerely appreciate the support of our Unitholders, and thank-you for investing in Focus. Be assured that your management team is patient, disciplined and committed to enhancing Unitholder value.

We would also like to thank our Board of Directors for their continued guidance and our team for their tireless efforts and continued enthusiasm.

On behalf of the Board,

Derek W. Evans
President and Chief Executive Officer

Operations Review

All of the producing properties of Focus are located in five main areas in Alberta and British Columbia. These are comprised of the natural gas dominated areas of Tommy Lakes, Kotcho-Cabin, Pouce Coupe and Sylvan Lake and the oil dominated area of Red Earth. The Trust has a high working interest in these properties and 80 percent of production in 2003 was operated by the Trust.

With the acquisition of additional working interests at Tommy Lakes on April 1, 2004 production of the Trust is weighted 73 percent to natural gas, our average working interest is 74 percent, and Focus operates approximately 87 percent its production.

The three most important producing areas are the Tommy Lakes and Kotcho-Cabin natural gas areas in northeastern British Columbia, and the Red Earth area in Alberta which produces light oil.

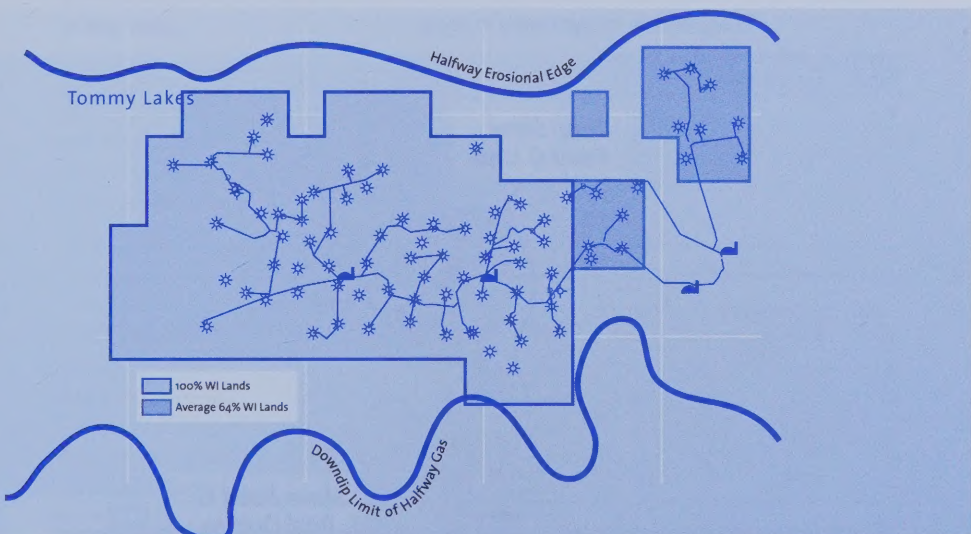
Tommy Lakes, NE British Columbia

The Trust's largest single asset and main natural gas producing property is the Tommy Lakes area in northeastern British Columbia. The main producing zone at Tommy Lakes is the areally extensive blanket sand of the Triassic Halfway formation. Total pool original gas in place is in excess of 600 bcf, of which approximately 24 percent has been produced to date. Although the reservoir is thick (more than 10 meters) and continuous, permeability is low, requiring all wells to be fracture stimulated to achieve stabilized rates of 600 to 800 mcf per day, with liquids recovered at 20 barrels per million cubic feet.

During 2003, Focus' gross production from the Tommy Lakes property averaged 17.3 mmcf per day of natural gas and 370 bbls per day of natural gas liquids from 72 (38 net) wells. The base decline rate on the existing production is approximately 12 percent per year. Production at the property is compressed at four Focus operated facilities and delivered into the Duke (Westcoast) system for further processing and delivery to markets. At December 31, 2003, Tommy Lakes represented approximately 48 percent of the Trust's reserves.

Subsequent to year-end the Trust has successfully completed its 13-well winter drilling program at Tommy Lakes. All of the 13 wells were cased and tied-in and the overall winter program at Tommy Lakes came in as per our expectations in terms of production and reserve volumes. Based upon the success of its drilling programs over the past two winters, Focus anticipates that the Tommy Lakes property will continue to be the main development area for the Trust, with at least two more years of similar sized development programs.

On April 1, 2004 Focus acquired additional working interests at Tommy Lakes for $110 million prior to adjustments. A more detailed description of the acquisition is provided in the section "Acquisition of additional Interests at Tommy Lakes April 1, 2004" on page 18. Subsequent to the acquisition, Tommy Lakes represents approximately 60 percent of the production and reserves of the Trust.



Kotcho-Cabin, NE British Columbia

At Kotcho-Cabin the Trust is producing a series of sour high pressure gas wells along a dolomitized reef edge in the Devonian Slave Point formation. The Kotcho-Cabin property is located approximately 80 kilometres northeast of Fort Nelson, British Columbia.

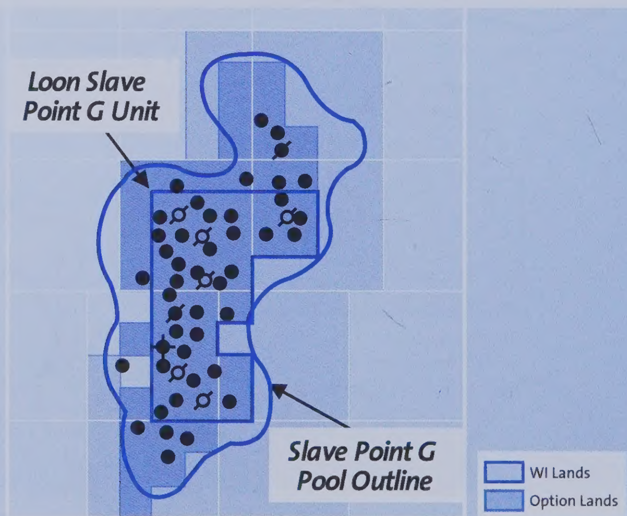
During 2003, Focus' gross production from this area averaged 12.0 mmcf per day of natural gas. Production from these properties is processed through 100 percent Focus-owned dehydration and water disposal facilities at Cabin and Kotcho and delivered to the Duke (Westcoast) system.

Red Earth, Alberta

The Trust's main light oil producing properties are focused in the Red Earth project area, which includes the Evi, Loon Lake, Loon North, Loon South, Golden, and Kitty properties. These properties are located approximately 125 kilometres northeast of the town of Peace River in north central Alberta. The oil produced in this area is 38° API light sweet crude. Approximately 40 percent of the Red Earth production is operated by Focus.

One of the major properties within the Red Earth area is Loon Lake, which was acquired in June 2003. The Loon Lake property represents the majority of the Trust's development opportunities within the Red Earth area. Development activities at Loon Lake will concentrate on waterflood optimization, infill drilling, and step-out drilling to better define and exploit the edges of the pool. Focus anticipates drilling four wells at Loon Lake in the remainder of 2004 and six to eight wells in 2005.

Loon Lake



Drilling

During 2003, the Trust participated in the drilling of 23 wells (9.3 net) with excellent drilling results and a success rate of 96 percent. The 2003 development program was weighted towards natural gas with 67 percent of net wells and 80 percent of capital expenditures in the field directed towards gas targets. Focus was the operator of 14 of the 23 wells drilled in 2003.

The Tommy Lakes area is the most significant development area of the Trust. Two thirds of the Trust's capital expenditures for 2003 were invested at Tommy Lakes for the drilling of nine (4.8 net) natural gas wells. This is a winter access only area. Of the nine wells, six were drilled and five tied-in during the first quarter of 2003, and three were drilled in the fourth quarter of 2003 and tied-in during the first quarter of 2004.

The Loon Lake property was acquired in June 2003 and the development program commenced with the drilling of eight oil wells (2.8 net). Results of the 2003 program have been good. Four wells were drilled in 2003 and brought on-stream in the Loon Lake Slave Point "G" Unit, for which Focus is the operator. An additional four wells were drilled on the non-unit lands to increase production, delineate the reservoir and to earn additional mineral rights. All of the non-unit wells were successful oil wells and two of the wells have been placed on production to date.

Additional activity in 2003 took place at Pouce Coupe with the drilling of two (1.3 net) natural gas wells in the Montney zone. Two oil wells (0.2 net) were drilled on the Ogston property, which is part of the Red Earth project area. The Trust had a 12 percent working interest in these wells, which were sold as part of the Ogston property disposition in July 2003. Focus participated in the drilling of two gas wells (0.2 net) at Lanaway, which is a property acquired in May 2003.

	2003				August 23 to December 31, 2002			
Drilling (Gross Wells)	**Oil**	**Gas**	**Abandoned**	**Total**	Oil	Gas	Abandoned	Total
Tommy Lakes, B.C.		**8**	**1**	**9**		5		5
Red Earth, Alberta	**2**			**2**	2			2
Loon Lake, Alberta	**8**			**8**				–
Pouce Coupe, Alberta		**2**		**2**				–
Lanaway, Alberta		**2**		**2**				–
	10	**12**	**1**	**23**	2	5	–	7

	2003				August 23 to December 31, 2002			
Drilling (Net Wells)	**Oil**	**Gas**	**Abandoned**	**Total**	Oil	Gas	Abandoned	Total
Tommy Lakes, B.C.		**4.3**	**0.5**	**4.8**		2.5		2.5
Red Earth, Alberta	**0.2**			**0.2**	0.2			0.2
Loon Lake, Alberta	**2.8**			**2.8**				–
Pouce Coupe, Alberta		**1.3**		**1.3**				–
Lanaway, Alberta		**0.2**		**0.2**				–
	3.0	**5.8**	**0.5**	**9.3**	0.2	2.5	–	2.7

Undeveloped Land

At December 31, 2003 Focus had undeveloped land of 14,449 net acres. On April 1, 2004 the Trust acquired additional interests at Tommy Lakes, including 11,040 net acres of undeveloped land. With the acquisition, Focus has approximately 25,489 net acres of undeveloped land with an average working interest of 79 percent. Net undeveloped land is in the Tommy Lakes area (78 percent), Loon Lake (nine percent), Pouce Coupe (two percent), Kotcho (nine percent) and other areas (three percent).

	December 31, 2003		**Acquisition April 1, 2004 Additional Interest at Tommy Lakes (1)**		**Total (1)**	
Undeveloped Acres	Gross	Net	Gross	Net	Gross	Net
Alberta	7,241	3,400	-	-	7,241	3,400
British Columbia	22,816	11,049	20,060	11,040	24,894	22,089
	30,057	14,449	20,060	11,040	32,135	25,489

(1) The additional interests acquired generally increase the net working interest ownership on undeveloped lands in which Focus already has an ownership interest

Focus had average production in 2003 of 8,548 BOE per day, with a weighting of 67 percent towards natural gas. During the year, Focus offset the natural production declines of its properties through the reinvestment of approximately 25 percent of funds flow from operations. The most significant production additions resulted from the winter drilling in the Tommy Lakes area.

Focus has had a very active drilling program at Tommy Lakes this past winter and thirteen natural gas wells have been brought on-stream in late March 2004. With the significance of winter drilling operations, Focus will continue to have its highest production volumes in the second quarter of the year as a result of flush production. For 2004, Focus is expecting to average 10,000 BOE per day including the acquisition of additional working interests at Tommy Lakes in April 2004.

	2003				August 23 to December 31, 2002			
Production By Area	**Oil (bbls/d)**	**Natural Gas (mcf/d)**	**NGL (bbls/d)**	**BOE/d**	Oil (bbls/d)	Natural Gas (mcf/d)	NGL (bbls/d)	BOE/d
Tommy Lakes, B.C.		**17,251**	**370**	**3,246**		14,058	334	2,677
Kotcho-Cabin, B.C.		**11,978**		**1,996**		11,635		1,939
Red Earth, Alberta (1)	**2,056**			**2,056**	2,420			2,420
Loon Lake, Alberta (2)	**218**			**218**				
Pouce Coupe, Alberta	**10**	**3,256**	**22**	**574**	9	3,175	23	561
Sylvan Lake, Alberta	**55**	**1,689**	**90**	**427**	82	2,016	100	518
Lanaway, Alberta (3)	**15**	**81**	**3**	**31**				
	2,354	**34,254**	**485**	**8,548**	2,511	30,884	457	8,115

(1) Includes July 1, 2003 disposition of interests at Ogston with production of approximately 47 bbls/d.
(2) Loon Lake acquisition closed June 1, 2003. Loon Lake is adjacent to our Red Earth interests.
(3) Lanaway acquisition closed May 1, 2003. Lanaway is adjacent to our Sylvan Lake interests.

	2003				2002
Production by Quarter	**Q4**	Q3	Q2	**Q1**	Q4
Oil (bbls/d)	**2,278**	2,336	2,361	**2,444**	2,469
Natural gas (mcf/d)	**32,475**	33,593	36,815	**34,158**	32,908
NGL (bbls/d)	**460**	508	501	**471**	464
BOE/d	**8,151**	8,443	8,997	**8,608**	8,418

Year-End Reserves Review

Year-End Reserves

Based on independent engineering evaluations conducted by Paddock Lindstrom and Associates Ltd. ("Paddock") and McDaniel and Associates Consultants Ltd. ("McDaniel") effective December 31, 2003, Focus had proved plus probable reserves of 29.6 mmboe, an increase of 6 percent from the 27.8 mmboe recorded at December 31, 2002. Year-end reserves were evaluated in accordance with National Instrument 51-101 ("NI 51-101"). Under NI 51-101's revised reserve definitions and evaluation standards, proved plus probable reserves represent a "best estimate" and as a result are comparable to prior years "established" reserves which comprised proven reserves plus 50 percent of probable reserves.

Paddock and McDaniel evaluated 100 percent of the Trust's reserves. The portion of the evaluation conducted by Paddock represented 79 percent of the proved plus probable reserves and 77 percent of the associated future net revenue discounted at 10%. The remaining reserves and associated future net revenue were evaluated by McDaniel. The Paddock January 1, 2004 price forecast was used in the future net revenue determinations for both evaluations. The Trust's Reserves Committee, comprising independent and qualified directors of the Trust, has reviewed and approved the reports prepared by Paddock and McDaniel and other pertinent reserves data.

Proved developed producing reserves represent 54 percent of proved plus probable reserves, while total proved reserves represent 77 percent of total proved plus probable reserves. On a BOE basis, total proved plus probable reserves are comprised 71 percent natural gas, 22 percent light crude oil and 7 percent natural gas liquids. On a proven basis technical revisions were negative 2.2 mmboe, or approximately 9 percent of the opening balance. On a proved plus probable basis, technical revisions were positive 0.4 mmboe, or 1 percent of the opening balance. In both cases, the revisions were due to the combination of the new standards mandated by NI 51-101 and performance changes on producing properties.

Net Present Value of Future Net Revenue

The estimated net present value of Focus' crude oil, natural gas and natural gas liquids reserves was evaluated using Paddock's January 1, 2004 price forecast prior to provision for income taxes, interest, debt service charges and general and administrative expenses. At a 10 percent discount rate, the net present value of the Trust's proved plus probable reserves was $273.0 million. Proved producing and total proved reserves make up respectively 68 percent and 84 percent of the total proved plus probable value.

Reserve Life Index

Focus' proved plus probable RLI at year-end 2003 was 9.8 years while the proved RLI was 7.7 years. These RLI's are calculated using period-end reserves and forward-year forecast production from the reserves report.

Reserve Addition Costs

Under NI 51-101, the methodology to be used to calculate FD&A costs includes incorporating changes in future development capital ("FDC") required to bring the proved undeveloped and probable reserves to production. On a proved plus probable basis, Focus' 2003 reserve addition costs were $7.88 per BOE including acquisitions and divestitures or $7.31 per BOE excluding acquisitions and divestitures. These values include future development capital of $42.5 million. As previously noted, this year's proved plus probable reserves are compared to prior year's established reserves which risked probable reserves at 50 percent. On a total proven basis reserve addition costs were not meaningful due to revisions and the impact of NI 51-101.

Reserves Information

The following cautionary statements are specifically required by NI 51-101.

1. It should not be assumed that the estimates of future net revenues presented in the tables represent the fair market value of the reserves. There is no assurance that the constant prices and costs assumptions and forecast prices and costs assumptions will be attained and variances could be material.

2. Disclosure provided herein in respect of BOEs may be misleading, particularly if used in isolation. In accordance with NI 51-101, a BOE conversion ratio of 6 mcf:1 bbl has been used in all cases in this disclosure. This BOE conversion ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

3. The aggregate of the exploration and development costs incurred in the most recent financial year and the change during the year in estimated future development costs generally will not reflect total finding and development costs related to reserve additions for that year.

4. Estimates of reserves and future net revenues for individual properties may not reflect the same confidence level as estimates of reserves and future net revenues for all properties due to the effects of aggregation.

5. In all cases, the F&D, or FD&A cost is calculated by dividing the identified capital expenditures by the applicable reserves additions.

Company Gross Reserves at December 31, 2003
(before deduction of royalties payable, not including royalties receivable)
(based on Forecast Prices and Costs)

	Light Crude Oil (mbbl)	Natural Gas (mmcf)	NGLs (mbbl)	Oil Equivalent (mboe)
Proved Producing	3,935	65,931	1,160	16,084
Proved Non-producing	221	8,146	80	1,659
Total Proved Developed	**4,156**	**74,077**	**1,240**	**17,743**
Proved Undeveloped	806	22,411	363	4,903
Total Proved	**4,962**	**96,488**	**1,603**	**22,646**
Probable Additional	1,536	29,872	434	6,949
Total Proved + Probable	**6,498**	**126,360**	**2,037**	**29,595**

Company Net Reserves at December 31, 2003
(after deduction of royalties payable, including royalties receivable)
(based on Forecast Prices and Costs)

	Light Crude Oil (mbbl)	Natural Gas (mmcf)	NGLs (mbbl)	Oil Equivalent (mboe)
Proved Producing	3,391	49,399	903	12,527
Proved Non-producing	**208**	**6,100**	**64**	**1,289**
Total Proved Developed	3,599	55,499	967	13,816
Proved Undeveloped	744	17,390	291	3,933
Total Proved	**4,343**	**72,889**	**1,258**	**17,749**
Probable Additional	1,353	22,204	341	5,395
Total Proved + Probable	**5,696**	**95,093**	**1,599**	**23,144**

2003 RESERVE RECONCILIATION

Company Gross Reserves
(before deduction of royalties payable, not including royalties receivable)

	Light Crude Oil (mbbl)	Natural Gas (mmcf)	NGLs (mbbl)	Oil Equivalent (mboe)
TOTAL PROVED				
December 31, 2002	5,034	106,915	1,666	24,519
Discoveries	51	1,089	23	256
Extensions	40	2,008	21	396
Improved Recovery	412	0	0	412
Technical Revisions	(1,578)	(3,774)	(10)	(2,216)
Economic Factors	0	0	0	0
Acquisitions	1,987	2,764	83	2,530
Dispositions	(128)	(11)	0	(130)
Production	(856)	(12,503)	(181)	(3,120)
December 31, 2003	**4,962**	**96,488**	**1,603**	**22,646**
PROBABLE (1)				
December 31, 2002	497	15,619	227	3,327
Discoveries	25	172	4	57
Extensions	18	291	3	69
Improved Recovery	565	0	0	565
Technical Revisions	213	13,249	183	2,605
Economic Factors	0	0	0	0
Acquisitions	283	545	17	391
Dispositions	(64)	(4)	0	(65)
Production	0	0	0	0
December 31, 2003	**1,536**	**29,872**	**434**	**6,949**
PROVED PLUS PROBABLE (1)				
December 31, 2002	5,531	122,534	1,893	27,846
Discoveries	76	1,261	27	313
Extensions	58	2,299	24	465
Improved Recovery	977	0	0	977
Technical Revisions	(1,365)	9,475	174	388
Economic Factors	0	0	0	0
Acquisitions	2,269	3,309	100	2,921
Dispositions	(192)	(15)	0	(195)
Production	(856)	(12,503)	(181)	(3,120)
December 31, 2003	**6,498**	**126,360**	**2,037**	**29,595**

1) December 31, 2002 Probable reserves presented are risked at 50%.

2) All reserves are based on forecast prices and costs.

NET PRESENT VALUE SUMMARY

Net Present Value of Future Net Revenue Before Income Taxes – Forecast Prices and Costs (including ARTC)

($ thousands)	Undiscounted	Discounted at 5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
Proved Producing	270,044	217,816	184,760	161,865	145,010
Proved Non-producing	22,452	16,596	13,161	10,912	9,325
Total Proved Developed	**292,496**	**234,412**	**197,921**	**172,777**	**154,335**
Proved Undeveloped	67,438	45,580	32,530	24,149	18,441
Total Proved	**359,933**	**279,992**	**230,451**	**196,926**	**172,776**
Probable Additional	107,446	63,852	42,529	30,543	23,118
Total Proved + Probable	**467,379**	**343,844**	**272,980**	**227,469**	**195,894**

January 1, 2004 Price Forecast – Paddock Lindstrom and Associates Ltd.

	WTI Crude Oil $US/bbl	Edmonton Light Crude Oil $CDN/bbl	Henry Hub Natural Gas $US/mmbtu	AECO C Natural Gas $CDN/mmbtu	Westcoast Station 2 Natural Gas $CDN/mmbtu	Exchange Rate $US/$CDN
2004	29.00	37.61	5.25	6.00	5.98	0.75
2005	26.50	34.25	4.75	5.31	5.29	0.75
2006	25.50	32.90	4.40	4.83	4.81	0.75
2007	25.00	32.21	4.45	4.87	4.85	0.75
2008	25.50	32.85	4.50	4.92	4.90	0.75
2009	26.01	33.51	4.55	4.96	4.94	0.75
2010	26.53	34.18	4.60	5.01	4.99	0.75
2011	27.06	34.86	4.65	5.05	5.03	0.75
Escalate thereafter at	2%/yr	2%/yr	2%/yr	2%/yr	2%/yr	0%/yr

Net Present Value of Future Net Revenue Before Income Taxes – Constant Prices and Costs (including ARTC)

($ thousands)	Undiscounted	Discounted at 5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
Proved Producing	382,969	300,807	249,993	215,432	190,377
Proved Non-producing	35,284	25,537	19,955	16,356	13,846
Total Proved Developed	**418,253**	**326,343**	**269,948**	**231,788**	**204,222**
Proved Undeveloped	104,447	72,138	53,072	40,827	32,435
Total Proved	**522,700**	**398,482**	**323,020**	**272,615**	**236,657**
Probable Additional	154,049	93,115	63,223	46,278	35,657
Total Proved + Probable	**676,749**	**491,597**	**386,244**	**318,893**	**272,313**

Constant Prices at December 31, 2003

	Edmonton Light Crude Oil $CDN/bbl	AECO C Natural Gas $CDN/mmbtu	Westcoast Station 2 Natural Gas $CDN/mmbtu
2004 and thereafter	40.28	6.72	6.61

FINDING AND DEVELOPMENT COSTS

Company Gross Reserves Excluding the Effect of Acquisitions and Dispositions (2)	2003	2002 (3)	2001 (3)	Three Year Total
Capital expenditures – $M	**16,589**	39,535	63,322	119,332
Net change in future development capital – $M				
Proven	**(2,506)**	14,140	2,066	13,700
Proven plus probable (1)	**(921)**	17,703	3,237	20,019
Total capital including change in future development capital – $M				
Proven	**14,083**	53,675	65,388	133,032
Proven plus probable (1)	**15,668**	57,238	66,559	139,351
Reserve additions – $M				
Proven	**(1,153)**	6,894	9,742	15,483
Proven plus probable (1)	**2,143**	7,912	10,700	20,755
Finding and development cost – $/BOE				
Proven	**n/a**	$7.79	$6.71	$8.59
Proven plus probable (1)	**$7.31**	$7.23	$6.22	$6.71

(1) Reserves and costs for 2001 and 2002 are presented on an established basis (proved plus probable risked at 50%).
(2) Reserves are based on forecast prices and costs.
(3) Includes activities of Storm Energy Inc. prior to the Plan of Agreement effective August 23, 2002.

FINDING, DEVELOPMENT AND ACQUISITION COSTS

Company Gross Reserves Including the Effect of Acquisitions and Dispositions (2)	2003	2002 (3)	2001 (3)	Total
Capital expenditures – $M	**36,805**	40,140	62,738	139,684
Net change in future development capital – $M				
Proven	**(94)**	14,140	2,066	16,112
Proven plus probable (1)	**1,579**	17,703	3,237	22,519
Total capital including change in future development capital – $M				
Proven	**36,711**	54,280	64,804	155,796
Proven plus probable (1)	**38,384**	57,843	65,975	162,203
Reserve additions – $M				
Proven	**1,247**	6,894	9,718	17,859
Proven plus probable (1)	**4,869**	7,912	10,674	23,455
Finding and development cost – $/BOE				
Proven	**$29.44**	$7.87	$6.67	$8.72
Proven plus probable (1)	**$7.88**	$7.31	$6.18	$6.92

(1) Reserves and costs for 2001 and 2002 are presented on an established basis (proved plus probable risked at 50%).
(2) Reserves are based on forecast prices and costs.
(3) Includes activities of Storm Energy Inc. prior to the Plan of Agreement effective August 23, 2002.

Net Asset Value

Net Asset Value (before tax) December 31, 2003

The following net asset value ("NAV") table shows what is commonly referred to as a "produce out" NAV calculation. The value is a snapshot in time and is based on various assumptions including commodity prices and foreign exchange rates that vary over time.

NAV at December 31, 2003

($thousands except per unit amounts)	Paddock Price Forecast	Constant Price Forecast
Value of Proved Plus Probable		
Reserves Discounted at 10%	272,980	386,244
Undeveloped Lands	1,815	1,815
Net Debt Including Working Capital	(24,641)	(24,641)
Reclamation Fund	1,030	1,030
Net Abandonment, Reclamation & Salvage (1)	(880)	(572)
Net Asset Value	250,304	363,876
Units Outstanding (thousands)	31,822	31,822
Per Unit	$ 7.87	$ 11.43

(1) In addition to abandonment and reclamation liability already included in Reserve Reports.

Focus' NAV at year-end 2003 was $7.87 per unit using forecast prices. After giving effect to the recently announced Tommy Lakes acquisition and subsequent unit issue, the proforma NAV of the Trust is estimated to be approximately $8.49 per unit using forecast prices.

Acquisition of Additional Interests at Tommy Lakes April 1, 2004

On March 8, 2004, Focus announced that it had entered into an agreement, subject to the usual conditions to close, to acquire additional working interests at its Tommy Lakes property in northeastern British Columbia for $110 million. The effective date of the agreement and the close date was April 1, 2004.

The interests acquired had average production per day for January and February 2004 of approximately 11.7 mmcf per day of natural gas and 250 barrels per day of natural gas liquids. Total proved and probable reserves for the property are 11.7 million barrels of oil equivalent, being 62.4 bcf of natural gas and 1.3 million barrels of natural gas liquids. Proven reserves represent 76.5 percent of total proved and probable reserves. Reserves are based on an independent engineering evaluation conducted by Paddock Lindstrom & Associates Ltd. effective April 1, 2004 and prepared in accordance with National Instrument 51-101. The acquisition represents 20,060 gross acres of undeveloped land (11,040 net acres), and the associated ownership in natural gas gathering and processing facilities.

Reserves Data

The reserves data set forth below for the Tommy Lakes interests acquired April 1, 2004 are based upon an evaluation by Paddock dated March 1, 2004 with an effective date of April 1, 2004. The Reserves Data summarizes the oil, liquids and natural gas reserves of the acquired interests and the net present values of future net revenue for these reserves using forecast prices and costs. The Reserves Data conforms with the requirements of National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities ("NI 51-101"). FET Resources engaged Paddock to provide an evaluation of proved and proved plus probable reserves and no attempt was made to evaluate possible reserves. There is no assurance that forecast prices and costs assumptions will be attained and variances could be material. The reserves data should be read in conjunction with the Reserves Information on page 12 which sets out the cautionary statements that are specifically required by NI 51-101.

Company Gross Reserves at April 1, 2004 – Forecast Prices and Costs

	Natural Gas		Natural Gas Liquids	
	Gross (mmcf)	Net (mmcf)	Gross (mbbl)	Net (mbbl)
Proved Producing	39,041	29,335	820	660
Proved Non-Producing	1,124	848	23	19
Total Proved Developed	40,165	30,183	843	679
Proved Undeveloped	7,601	5,702	160	128
Total Proved	47,766	35,885	1,003	807
Probable Additional	14,603	10,959	307	247
Total Proved + Probable	62,369	46,844	1,310	1,054

Net Present Values of Future Net Revenue Before Income Taxes – Forecast Prices and Costs

($ thousands)	Undiscounted	Discounted at 5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
Proved Producing	121,996	92,544	76,027	65,427	58,003
Proved Non-Producing	3,321	2,562	2,098	1,789	1,569
Total Proved Developed	125,317	95,106	78,125	67,216	59,572
Proved Undeveloped	18,572	11,901	8,447	6,391	5,042
Total Proved	143,889	107,007	86,572	73,607	64,614
Probable Additional	40,693	23,291	15,443	11,152	8,501
Total Proved + Probable	184,582	130,298	102,015	84,759	73,115

April 1, 2004 Price Forecast – Paddock Lindstrom and Associates Ltd.

	WTI Crude Oil ($US/bbl)	Edmonton Light Crude Oil ($CDN/bbl)	AECO C Natural Gas ($CDN/MMBtu)	Natural Gas Liquids FOB Field Gate ($CDN/BBL)	Exchange Rate ($US/$CDN)
2004	30.00	38.94	6.00	32.70	0.75
2005	27.50	35.58	5.31	29.10	0.75
2006	25.50	32.90	4.83	26.16	0.75
2007	25.00	32.21	4.87	24.89	0.75
2008	25.50	32.85	4.92	24.65	0.75
2009	26.01	33.51	4.96	24.39	0.75
2010	26.53	34.18	5.01	24.89	0.75
2011	27.06	34.86	5.05	25.38	0.75
Thereafter	Escalated at 2%/year	Escalated at 2%/year	Escalated at 2%/year	Escalated at 2%/year	

The following is a discussion and analysis of the operating and financial results of Focus for the year ended December 31, 2003 compared with the prior year as well as information and opinions concerning the Trust's future outlook based on currently available information. **This discussion is dated March 24, 2004 and should be read in conjunction with the Trust's audited consolidated financial statements for the years ended December 31, 2003 and 2002, together with accompanying notes.**

Throughout the discussion, we use the term funds flow from operations ("funds flow" before changes in non-cash working capital). Funds flow is used by management to analyze operating performance and leverage. Funds flow as presented does not have any standardized meaning prescribed by Canadian GAAP and therefore it may not be comparable with the calculation of similar measures of other entities. Funds flow as presented is not intended to represent operating cash flow or operating profits for the period nor should it be viewed as an alternative to cash flow from operating activities, net earnings or other measures of financial performance calculated in accordance with Canadian GAAP. All references to funds flow throughout this report are based on funds flow from operations before changes in non-cash working capital.

Per barrel of oil equivalent ("BOE") amounts have been calculated using a conversion of six thousand cubic feet of natural gas to one barrel of oil (6 mcf = 1 bbl).

Reorganization per Plan of Arrangement Effective August 23, 2002

On August 20, 2002 the shareholders of Storm Energy Inc. approved the Plan of Arrangement which resulted in Focus Energy Trust commencing operations on August 23, 2002. The Trust's operations commenced with the new legal structure and business mandate pursuant to the Trust Indenture dated July 15, 2002, and with a new management team.

Focus retained approximately 75 percent of the assets previously owned by Storm Energy Inc. These included all of the working interests in natural gas producing assets in the Tommy Lakes and Kotcho-Cabin areas of northeast British Columbia, the natural gas producing assets at Sylvan Lake and Pouce Coupe in Alberta as well as approximately 40 percent of the working interests in the oil producing areas in the Red Earth area of northern Alberta. This represented approximately 96 percent of the natural gas production and 46 percent of the oil production of Storm Energy Inc. prior to the Plan of Arrangement.

FET Resources Ltd., a wholly owned subsidiary of Focus, owns the oil and natural gas properties, and is the legal successor company to Storm Energy Inc. The transfer of assets to Storm Energy Ltd. on August 23, 2002 was a related party transaction at that time, and recorded at net book value. The financial statements for Focus Energy Trust are reported on a continuity of interests basis and include the financial results of Storm Energy Inc. to August 22, 2002.

The financial and operating results for the year ended December 31, 2003 reflect the operations and assets of the Trust. The financial and operating results for the year ended December 31, 2002 include the operations and assets of Storm Energy Inc. for the period January 1 to August 23, 2002 prior to the Plan of Arrangement.

Overall 2003 Performance

Focus completed its first full year of operations as a trust in 2003. Performance in 2003 reflects the strong commodity price environment, the quality of our assets, and the execution of our business strategy. Focus' strategy is to surface value on our existing assets, maintain cost efficiencies, maintain financial strength, and acquire quality assets. Production of the Trust was replaced through development programs at our key properties, and through the acquisition of quality properties which have development potential.

Funds flow from operations increased to $2.16 per Unit and cash distributions in respect of production commencing in April 2003 have been $0.14 per Unit per month. The distribution policy has been aimed at achieving consistency of distributions and sustainability through balancing funds flow with distributions and capital programs.

Operations Summary

	Years Ended, December 31,			
		2003		2002
Average daily production				
Crude oil (bbls/d)		**2,354**		4,831
NGLs (bbls/d)		**485**		502
Natural gas (mcf/d)		**34,254**		32,316
Barrels of oil equivalent (BOE/d @ 6:1)		**8,548**		10,719
Percent Natural gas		**67%**		50%
Average product prices realized				
Crude oil ($CDN/bbl), before hedging settlements	**$**	**42.69**	$	38.27
Financial hedging settlements ($CDN/mcf)	**$**	**(1.95)**	$	(0.16)
NGLs ($CDN/bbl)	**$**	**34.24**	$	29.15
NGL price / Crude oil price		**80%**		76%
Natural gas ($CDN/mcf), before hedging settlements	**$**	**6.36**	$	3.59
Financial hedging settlements ($CDN/mcf)	**$**	**(0.82)**	$	0.08
Reference prices & Focus differential				
Crude oil (Edm. Light Price $CDN/bbl)	**$**	**42.89**	$	39.92
Differential	**$**	**(0.19)**	$	(1.65)
Natural gas (AECO daily $CDN/mcf)	**$**	**6.70**	$	4.08
Differential	**$**	**(0.34)**	$	(0.49)
Production revenue (thousands of dollars)				
Crude oil, before hedging settlements		**36,687**		67,473
Financial hedging settlements		**(1,678)**		(1,830)
NGLs		**6,062**		5,342
Natural gas, before hedging settlements		**79,572**		42,333
Financial hedging settlements		**(10,221)**		2,010
Mark to market adjustment		**1,353**		(1,353)

		Years Ended, December 31,		
		2003		2002
Funds flow per BOE				
Revenue (before hedging settlements)	$	**39.22**	$	29.59
Financial hedging settlements ($CDN)		**(3.80)**		0.05
Revenue (including hedging settlements)		**35.41**		29.64
Royalties, net of ARTC		**(9.78)**		(7.08)
Production expenses		**(3.39)**		(3.32)
Netback		**22.24**		19.24
Facility income		**0.84**		0.40
Interest income		**0.02**		0.05
Technical Services Agreement		**(0.67)**		(0.38)
General and administrative, cash portion		**(0.81)**		(0.72)
Interest and financing and other		**(0.44)**		(0.63)
Reorganization expenses		**–**		(3.25)
Current and large corporations tax		**(0.07)**		(0.52)
	$	**21.09**	$	14.17
Royalties percent of revenue (before hedging settlements)		**25%**		24%

Production

Focus has five key operating areas in Alberta and northeastern British Columbia. Production in 2003 was weighted 67 percent towards natural gas and Focus was the operator of 80 percent of production. The increase in average natural gas production for 2003 reflects a concentration of capital expenditures on natural gas properties, primarily at Tommy Lakes, British Columbia and Pouce Coupe, Alberta. During 2003, Focus also acquired light oil properties at Lanaway and Loon Lake. Both of these acquired properties have significant development opportunities, and development programs commenced in 2003.

Excluding the acquisitions and the disposition of interests at Ogston, volumes in 2003 were approximately 170 BOE per day (or 2%) behind our original estimate. This was the result of third party processing plant problems and higher than expected decline rates within the Red Earth area.

The Tommy Lakes natural gas property contributed 38 percent of the production of the Trust in 2003 and is the largest property of the Trust. The increase in natural gas production of the Trust in the first half of 2003 largely reflects flush production from the 2002 / 2003 winter development program at Tommy Lakes. New wells came on-stream in February and March of 2003 and then declined to their stabilized production rate. Focus is currently in the final stages of completing the 2003 / 2004 winter development program at Tommy Lakes, and 13 additional wells have been drilled and brought on-stream. Tommy Lakes is operated by Focus and contains the main development opportunities of the Trust for 2004 and 2005.

The acquisition of additional working interests announced on March 8, 2003 significantly increases Focus' working interests in this property, further increasing our emphasis on natural gas and on being the operator of our production. The acquisition is expected to close April 1, 2004.

Compared with 2002, production volume is lower as a result of the transfer out of oil producing assets, as per the Plan of Arrangement.

Additional information on 2003 production by area and by quarter is contained in the section "Production" on page 10.

Pricing and Price Risk Management

Natural gas production in Alberta and British Columbia is priced with reference to delivery at the AECO Hub in Alberta. AECO daily average natural gas prices in 2003 increased 64 percent to average \$6.70 per mcf compared with \$4.08 per mcf in 2002.

The price per mcf realized by Focus in 2003, before adjustment for financial hedges, of \$6.36 represents a discount of \$0.34 to the AECO reference price for the period. The net price realized on natural gas sales reflects specific markets being delivered to, deductions to the delivery point for transportation and liquids recovery processing, the heat content of the natural gas, and physical delivery contract terms. In 2003, we delivered approximately 15 percent of our natural gas production in Alberta, 57 percent of our natural gas production to Station 2 near Fort St. John, British Columbia, and 25 percent of our natural gas production to Sumas on the British Columbia–Washington border.

The average reference prices for crude oil in Canadian dollars, being the refiners' posted prices at Edmonton, Alberta, increased seven percent for 2003 compared with 2002. This increase is the net impact of the rising reference price for West Texas Intermediate crude oil at Cushing, Oklahoma (WTI) partially offset by a strengthening of the Canadian dollar. Crude oil prices received are based on the refiners' posted prices at Edmonton, less deductions for transportation from the field and adjustments for quality.

The Trust's crude oil production consists entirely of light sweet crude oil (average 38° API gravity). The prices realized in 2003 and 2002, before adjustment for hedges, were at a small discount to the Edmonton posted price, reflecting the high quality of our crude oil. Our price for crude oil, before adjustment for hedges, increased by 12 percent as a result of the higher base price and the reduced differential of our oil to the Edmonton posted prices.

Focus utilizes a hedging program to manage exposure to fluctuations in commodity prices, to provide greater certainty and stability to distributions, to protect Unitholder return on investment and to help ensure profitability of specific properties or acquisitions. This program is monitored by the Board of Directors and implemented by the Risk Management Committee. We use financial instruments and physical forward sales as part of this risk management program. All of the commodity and foreign exchange contracts are with parties that represent minimal counterparty risk.

Production income for 2003 includes a net loss of $10.6 million relating to financial instruments associated with commodity and foreign exchange contracts. This compares with a net loss of $1.2 million relating to financial instruments associated with commodity and foreign exchange contracts in 2002. The net loss in 2003 is a combination of a hedging loss of $8.9 million for financial instruments associated with natural gas and a hedging loss on crude oil of $1.7 million. The hedging results for natural gas include a non-cash gain of $1.4 million relating to a natural gas ceiling contract that was accounted for based on the mark to market value. These hedging losses reflect commodity prices for 2003 that were significantly higher than the forward market. On a quarter by quarter basis for 2003, hedging losses were $8.4 million in the first quarter, $1.7 million in the second quarter, $0.4 million in the third quarter, and $0.1 million in the fourth quarter. The results for the first quarter of 2003 are a result of the extremely strong natural gas prices during this period.

A summary of the financial instruments and physical sales contracts at December 31, 2003, and their estimated mark to market values, are described in Note 10 and Note 11 of the Notes to Consolidated Financial Statements.

Focus currently has a combination of fixed price arrangements and collars that provide price protection in 2004 on an average 17,204 mcf per day of natural gas production at a reference price of $CDN 6.40 per mcf. With respect to crude oil, fixed price swaps represent 1,400 bbls per day of oil production with a reference price of $CDN 37.59 per barrel. The following table details financial instruments and physical contracts as at March 24, 2004 as part of the Trust's hedging program for 2004 and 2005.

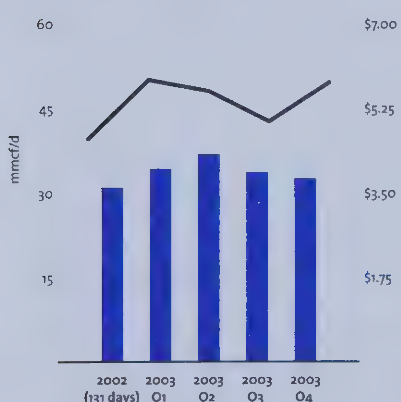
Financial Contracts	Daily Quantity	Contract Price	Price Index	Term
Crude oil – fixed price	500 bbls	$ 41.80 CDN	WTI	September 2003 – August 2004
	900 bbls	$ 35.63 CDN	WTI	September 2003 – December 2004
	500 bbls	$ 43.49 CDN	WTI	September 2004 – December 2004
Natural gas – costless collar	6,420 GJ	$ 5.75 – $8.03 CDN	AECO	November 2003 – March 2004

Physical Contracts	Daily Quantity	Contract Price	Delivery Point	Term
Natural gas – fixed price	5,000 MMBTU	$ 8.21 CDN	Sumas	November 2003 – March 2004
	5,000 GJ	$ 7.21 CDN	Stn.2, B.C.	November 2003 – March 2004
	5,000 GJ	$ 6.11 CDN	Stn.2, B.C.	November 2003 – October 2004
	6,000 GJ	$ 5.20 CDN	Stn.2, B.C.	April 2004 – October 2004
	7,000 GJ	$ 5.13 CDN	Stn.2, B.C.	April 2004 – October 2004
	6,000 GJ	$ 5.68 CDN	Stn.2, B.C.	April 2004 – October 2004
	5,000 GJ	$ 6.47 CDN	Stn.2, B.C.	November 2004 – March 2005

Production Revenue

For the year ended December 31, 2003, production revenue was $111.8 million, comprised 62 percent of natural gas sales, 33 percent of crude oil sales and five percent from sales of natural gas liquids. Compared with 2002, 2003 had very strong prices for both natural gas and crude oil which largely offset the reduction in production volumes associated with the Plan of Arrangement effective August 23, 2002.

Natural Gas Volumes & Realized Price per MCF



Crude Oil Production & Realized Price per Barrel (excl. NGLs)

Royalties

Royalties, excluding hedging and net of Alberta royalty tax credit, as a percentage of revenue were 25 percent in 2003 compared with 24 percent in 2002. The effective royalty percentage in 2003 was 28 percent versus the 24 percent reported for 2002, reflecting higher hedging losses from financial instruments. Hedging gains and losses associated with financial instruments are not recognized for royalty calculations.

Other Income

Other income for 2003 includes $2.4 million for treating and processing third party oil and gas at our production facilities compared with $1.6 million in 2002. The higher level of treating and processing income for 2003 was a result of increased third party volumes processed at the Kotcho facilities in British Columbia. In addition to Kotcho, we earn third party processing revenue at our facilities located in the Sylvan Lake and Golden areas of Alberta.

Production Expenses

Production expenses for the year amounted to $3.39 per BOE. The main natural gas properties are in winter only access areas of British Columbia, and production expenses per BOE are the highest in the first and fourth quarters when these properties are accessible for maintenance and the bringing in of supplies. We have lower than average production expenses per BOE due to a higher weighting towards natural gas production, having significantly higher production per well compared to the sector average, and by being the operator of our major properties.

Technical Services Agreement

Our Technical Services Agreement with Storm Energy Ltd. expired on June 30, 2003. Through that arrangement, we received services in respect of the operation of the assets and associated administrative services for a fee of $350,000 per month. The services previously provided under the agreement are now performed by employees of the Trust.

General and Administrative Expenses

(thousands)	**2003**	August 23 to December 31, 2002	2002
Gross G&A, before Trust Unit Rights Plan expense (i) (ii) (iii)	**$4,602**	$1,106	$4,990
Overhead recoveries	**(1,221)**	(240)	(1,890)
	3,381	866	3,100
Trust Unit Rights Plan expense (iv)	**246**	–	–
Net G&A	**$3,627**	$866	$3,100
Cash based G&A Expense Per BOE	**$0.81**	$0.55	$0.72
Non-cash G&A Expense Per BOE	**0.35**	0.26	0.07
G&A per BOE	**$1.16**	$0.81	$0.79

(i) Amounts paid to Storm Energy Ltd. in accordance with the Technical Services Agreement are reported separately on the Consolidated Statements of Income and Accumulated Income, and not included as part of general and administrative expenses.

(ii) Gross general and administrative expenses for 2002 do not include $12.7 million in expenses associated with the reorganization, which are reported separately on the Consolidated Statements of Income and Accumulated Income.

(iii) Gross general and administrative expenses for 2003 include $1.7 million associated with the Executive Bonus Plan. This compares with $0.6 million for the 131 day period in 2002 after the Plan of Arrangement. Half of this amount is settled through the issuance of units from treasury at a price equal to the last five trading days of the month for which the bonus relates.

(iv)Trust Unit Rights Plan compensation expense is calculated using the fair value method adopted in the fourth quarter of 2003 and represents a non-cash charge. Details of this compensation expense are contained in Note 8 of the Notes to Consolidated Financial Statements.

Increased general and administrative expenses in 2003 result from increased staff levels and office expenses corresponding to the expiry of the Technical Services Agreement on June 30, 2003.

As operator, capital recoveries are based on a percentage of the total capital program managed. We operate the majority of our capital programs during the winter season. As such, almost all of the capital recoveries occur in the winter months.

No general and administrative expenses were capitalized in 2003 or 2002.

Interest and Financing Expenses

Interest expenses decreased to $1.4 million in 2003 from $2.5 million in 2002. This decrease is attributable to lower monthly average debt balances and lower interest rates. At December 31, 2003, $21.4 million was drawn on the revolving term credit facility. At December 31, 2002, Focus had long-term debt of $51.8 million and cash and cash equivalents of $14.7 million relating to short-term investments in a subsidiary. These investments matured and were applied to the long-term debt in 2003. Borrowings under the credit facilities bear interest at the bank prime rate or Canadian banker's acceptance rates plus a bank stamping fee.

Depletion, Depreciation, and Provision for Site Restoration and Abandonment

The 2003 depletion and depreciation provision is $7.82 per BOE compared with $7.89 per BOE for the period of August 23 to December 31, 2002. The increase reflects actual capital expenditures and updated estimates of proven reserves. The estimate of future capital expenditures for proven reserves used in the calculation of the depletion and depreciation provision rate remained essentially unchanged at $28.4 million.

The acquisition of the additional working interests at Tommy Lakes which is scheduled to close on April 1, 2004 will increase the depletion and depreciation expense slightly in the second quarter of 2004.

The 2003 provision for site restoration and abandonment was $0.32 per BOE compared with $0.22 per BOE for the period August 23 to Dcember 31, 2002. The increase is largely due to the separation of expected realizable salvage values, and also reflects updated estimates of expected future costs and an increase in the number of wells as a result of development and acquisition activity.

In the first quarter of 2004, we will adopt the CICA new section 3110, Asset Retirement Obligations. This new standard requires that companies recognize the liability associated with future site reclamation costs in the financial statements at the time when the liability is incurred. This liability is initially measured at fair value and subsequently adjusted for the accretion of the discount amount and any changes in the underlying cash flows. The asset retirement cost is capitalized to the related asset and amortized into earnings over time.

The Trust is currently evaluating the impact of this standard on its financial statements and does not anticipate it will have a material impact on earnings. This new standard does not have an impact on funds flow from operations.

Abandonments

We actively manage the exposure to environmental issues and abandonment and reclamation of well sites and facilities. The field operations are generally new in nature, concentrated to a few operating areas and do not have a significant number of shut-in wells. We conduct our operations to minimize risk and environmental impacts. Our employees and third parties regularly conduct reviews of wells and facilities.

We have established a reclamation fund for the purpose of funding estimated future environmental and reclamation obligations. At December 31, 2003 the reclamation fund had a balance of $1,030,000.

Reorganization Expenses

We incurred reorganization expenses in 2002 of $12.7 million associated with the Plan of Arrangement, of which $9.6 million relate to the cancellation of stock options and $3.1 million of advisory and other professional services costs.

Income and Other Taxes

(thousands)		**2003**		2002
Future income tax	$	**(816)**	$	6,673
Current and large corporations tax		**224**		2,052
Income and other taxes	$	**(592)**	$	8,725

In 2003, a future income tax recovery of $0.8 million was included in income compared to an expense of $6.7 million in 2002. The 2003 future income tax recovery is largely due to reductions in federal and provincial income tax rates. The reductions in future federal income tax rates were substantively enacted late in the second quarter of 2003 and were subsequently legislated in the fourth quarter of 2003. The legislation reduces the federal general corporate income tax rate on income from resource activities from 28 percent to 21 percent and eliminates the existing 25 percent resource allowance deduction and introduced the deductibility of actual provincial and other Crown royalties paid all over a five year period. As a result of these changes, as well as a reduction in the Alberta corporate income tax rate from 13 percent to 12.5%, the expected future income tax rate is 37 percent compared to 42 percent at December 31, 2002.

As a result of the change in corporate income tax rates, the Trust recorded a future income tax recovery of $3.3 million in 2003.

At December 31, 2003, a liability of $41.8 million for future income taxes was recorded on the balance sheet. Under our structure, payments made by our subsidiary FET to the Trust transfer both income and future tax liability from FET to the individual Unitholders. Therefore it is the opinion of management that payments from FET through to Focus will greatly reduce or eliminate future income taxes. These payments in a period reduce future income tax liabilities previously recorded by FET, and are recognized as a recovery of income tax in the period incurred.

At December 31, 2003 we had approximately $9.9 million in income tax pools that will be utilized to reduce the taxable portion of future cash distributions. FET and its subsidiary have approximately $40 million in income tax pools that will be utilized to minimize future income taxes at the legal entity level.

Our capital taxes were $0.9 million in 2003 and 2002.

Capital Expenditures

Capital Expenditures (thousands)	**2003**	August 23 to December 31, 2002	2002
Land	$ **294**	$ 31	$ 1,219
Seismic	**–**	–	1,032
Drilling and completion	**9,787**	1,675	23,976
Facilities, recompletions & workovers	**6,654**	1,821	13,846
Field inventory	**(146)**	–	(682)
Net field operations	**16,589**	3,527	39,391
Administration assets	**220**	16	144
Petroleum and natural gas properties and equipment additions	**16,809**	3,543	39,535
Acquisition	**22,175**	605	605
Dispositions	**(1,959)**	–	–
Total Capital Expenditures	$ **37,025**	$ 4,148	$ 40,140

Petroleum & Natural Gas Property and Equipment Additions by Area

(thousands except wells drilled)	2003	Wells Drilled (gross)	August 23 to December 31, 2002	Wells Drilled (gross)
Tommy Lakes – 02/03 Winter Program	$ 8,225	6	$ 2,827	5
Tommy Lakes – 03/04 Winter Program	2,854	3		
Kotcho-Cabin, B.C.	80		5	
Red Earth, Alberta	553	2	454	2
Loon Lake, Alberta	2,322	8		
Pouce Coupe, Alberta	2,091	2	155	
Sylvan Lake, Alberta	280		86	
Lanaway, Alberta	184	2		
Administration assets	220		16	
	$16,809	23	$ 3,543	7

The majority of our 2003 capital program was conducted at Tommy Lakes, which is only accessible during the winter months. Of the $16.8 million in petroleum and natural gas property and equipment additions for 2003, 66 percent was invested at Tommy Lakes, 14 percent at the Loon Lake property acquired in June 2003, and 12 percent at Pouce Coupe for the drilling of two natural gas wells (net 1.25 wells). In addition, development on the Lanaway property acquired in May 2003 commenced with the drilling of two gas wells (net 0.2 wells).

Capital expenditures for the fourth quarter were concentrated on the winter program for Tommy Lakes. The total 2003/2004 winter program will drill 13 wells, refrac five wells and workover eight wells. We operate this program which is estimated to cost approximately $11.5 million net. All of the wells from this winter program have now been brought on production.

Acquisitions at Loon Lake and Lanaway were completed in the second quarter of 2003. The Lanaway and Loon Lake properties were acquired for approximately $4.7 million and $17.4 million respectively. The Trust also disposed of the Ogston oil properties for proceeds of approximately $2 million in the second quarter of 2003.

Capital expenditures in 2004 will concentrate on further development at Tommy Lakes, British Columbia and on further development at the Pouce Coupe and Loon Lake properties in Alberta.

Liquidity and Capital Resources

As at December 31, 2003 we had a working capital deficit of $3.3 million compared with working capital of $15.3 million as at December 31, 2002. The change in working capital is primarily due to the $14.7 million of short term funds on deposit December 31, 2002 which was applied to the long-term debt early in 2003.

Total debt outstanding at December 31, 2003 was $21.4 million compared to $51.8 million at December 31, 2002. Focus has a $70.0 million revolving term credit facility with a Canadian financial institution, and a $10 million operating facility secured by its oil and gas properties. The current credit facility revolves until May 31, 2004. Focus has received an Offer of Extension of the revolving period for a further 364 days.

At December 31, 2003 long-term debt net of working capital was $24.6 million. This compares to $36.5 million at December 31, 2002. The $11.9 million reduction in net debt during this period resulted from the following factors.

- The distribution policy recognizes the number of Units that would be issued on conversion of the Exchangeable Shares. However, holders of Exchangeable Shares do not receive monthly cash distributions and we retain the cash. For 2003, this totaled approximately $9.8 million and the cash retained was used to reduce long-term debt.

- The issuance of Trust Units during 2003 raised net proceeds of $24.0 million. Acquisitions of properties, net of proceeds on disposition of Ogston, were $20.2 million. The balance of $3.8 million raised through the issuance of equity was applied to the debt. With respect to the acquisition at Loon Lake, the purchase price was reduced at closing by $3.2 million due to another working interest owner exercising their right of first refusal.

- Funding for capital expenditures from retained funds flow was $14.0 million, and the actual capital expenditures were $16.8 million.

Focus plans to finance its program for development drilling and enhancement of production through a combination of investing approximately 25 percent of funds flow and debt. Capital expenditures, including acquisitions, above this level will be financed through a combination of cash flow, debt and equity by issuing units from treasury.

During 2004, we will benefit from the retention of cash related to Exchangeable Shares not receiving monthly cash distributions. There are currently 2,415,481 Exchangeable Shares outstanding compared with 3,245,650 at December 31, 2003. The conversion of Exchangeable Shares into Units is at the sole discretion of the holders of the Exchangeable Shares.

Capitalization Table (thousands except per unit amounts)	**December 31, 2003**	**December 31, 2002**
Long-term debt	$ 21,337	$ 51,801
Less: Working capital (deficiency)	(3,304)	15,267
Net debt	$ 24,641	$ 36,534
Units outstanding and issuable for Exchangeable Shares	31,822	28,966
Market price at December 31	$ 15.00	$ 10.15
Market capitalization	$ 477,330	$ 294,005
Total capitalization	$ 501,971	$ 330,539
Net debt as a percentage of total capitalization	5%	11%
Funds flow (i)	$ 65,808	$ 52,946
Net debt to funds flow (i)	0.4	0.7

(i) December 31, 2002 is based on the funds flow from the operations of the Trust for the 131 day period

Funds Flow Reconciliation

(thousands except per unit amounts)		Year Ended Dec 31, 2003		Per Unit
Funds flow from operations	$	65,808	$	2.16
Less: Reclamation fund contributions		(1,030)	$	(0.03)
Less: Distributions calculated for Units and Exchangeable Shares		(50,771)	$	1.665
Plus: Distributions on Exchangeable Shares not paid in cash		9,846		
		23,853		
Capital expenditures – field operations		(16,809)	$	(0.55)
Change in net debt, before acquisitions, divestitures and equity issue	$	7,044		
Payout ratio – per Unit basis		77%		
Payout ratio – dollar basis		62%		

Cash Distributions

We announce our distribution policy on a quarterly basis. The actual amount of the cash distribution is determined by the Board of Directors and is dependent upon the commodity price environment, production levels, and the amount of capital expenditures to be funded from cash flow. Our distribution policy incorporates the withholding of up to 25 percent of cash flow for the financing of capital expenditures to provide more sustainable distributions. Cash distributions are essentially taxed to the Unitholders as ordinary income.

The Exchangeable Shares of FET Resources Ltd. are convertible into Trust Units of Focus based on the exchange ratio, which is adjusted monthly to reflect the cash distribution paid on the Trust Units. Cash distributions are not paid on the Exchangeable Shares and we retain the cash flow related to the Exchangeable Shares for reduction of debt or for additional capital expenditures. The initial exchange ratio was one Trust Unit for one Exchangeable Share. The exchange ratio increased to 1.16718 as at December 31, 2003. Effective March 15, 2004, the exchange ratio is 1.19599 Trust Units for one Exchangeable Share.

Taxation of Cash Distributions

Focus Energy Trust, for purposes of the Canadian Income Tax Act, is treated as a mutual fund trust and each year the Trust files an income tax return with the taxable income allocated to the Unitholders. Distributions paid to the Unitholders may be both a return on capital (income) and a return of capital. The allocation between these two streams is dependent upon the income tax deductions that the Trust is able to claim against the income it earns.

The Trust has net income for each year that is required to be calculated on an accrual basis of accounting, not a cash basis. Net income includes all interest income from FET and other income that accrues to the Trust to the end of the year. Under the Trust Indenture, net income of the Trust for each year will be paid or payable by way of cash distributions to the Unitholders.

Taxable income of the Trust includes a deduction for the allocation of taxable income to Unitholders, which is paid or becomes payable in the year and a deduction relating to income tax pools residing at the Trust level. The Trust Indenture provides that an amount at least equal to the taxable income of the Trust must be paid or payable each year to Unitholders in order to reduce the Trust's taxable income to zero. Such taxable income is allocated to Unitholders. Any taxable income relating to a payable amount is allocated to Unitholders of record at the end of the year, and each Unitholder receives a pro rata share of that payable amount.

2003 Canadian Income Tax Information

The following information is intended to assist Canadian holders of trust units of Focus Energy Trust (FET.UN – TSX) in the preparation of their 2003 T1 Income Tax Return. This summary is directed to a Unitholder who, for purposes of the Income Tax Act (Canada) is a resident of Canada and holds the Units as capital property. Other Unitholders are advised to consult with their tax advisor concerning their circumstances.

- **Trust Units held within an RRSP, RRIF or DPSP – NO AMOUNTS** are to be reported on the 2003 income tax return where trust units are held within a Registered Retirement Savings Plan (RRSP), Registered Retirement Income Fund (RRIF), Deferred Profit Savings Plan (DPSP) or any other such registered plans.

- **Trust Units held outside of an RRSP, RRIF or DPSP** – If the Trust Unit is held through a broker or other intermediary then the Unitholder will receive a T3 Supplementary slip directly from their broker or intermediary, not from the transfer agent (Valiant Trust Company) or from Focus, on or before March 30, 2004.

- If the Unitholder is a registered holder then the Unitholder will receive a T3 Supplementary slip directly from Valiant Trust Company.

- The amount reported in Box (26) on the T3 Supplementary slip, "Other Income", should be reported on the 2003 T1 Income Tax Return.

Taxable Income Allocated to Unitholders for 2003 and Taxation Treatment

- For those Unitholders who held their Focus Energy Trust Units outside of a registered plan, the return on capital or income portion is reported in Box (26) of the T3 Supplementary slip, "Other Income", and should be reported on the 2003 T1 Income Tax Return.

- In most circumstances, the return of capital portion will reduce the Unitholder's adjusted cost base of their Focus Energy Trust Units. This is discussed in more detail below.

- The following table outlines the breakdown of cash distributions per Unit paid by Focus Energy Trust with respect to record dates for the period January 31 to December 31, 2003.

Record Date	Payment Date	Distribution Paid	Taxable Income (Box 26 Other Income)	Return of Capital Amt.
January 31, 2003	February 17, 2003	$0.135	$0.0894*	$0.0026
February 28, 2003	March 17, 2003	$0.135	$0.1324	$0.0026
March 31, 2003	April 15, 2003	$0.135	$0.1324	$0.0026
April 30, 2003	May 15, 2003	$0.140	$0.1373	$0.0027
May 31, 2003	June 16, 2003	$0.140	$0.1373	$0.0027
June 30, 2003	July 15, 2003	$0.140	$0.1373	$0.0027
July 31, 2003	August 15, 2003	$0.140	$0.1373	$0.0027
August 31, 2003	September 15, 2003	$0.140	$0.1373	$0.0027
September 30, 2003	October 15, 2003	$0.140	$0.1373	$0.0027
October 31, 2003	November 17, 2003	$0.140	$0.1373	$0.0027
November 30, 2003	December 15, 2003	$0.140	$0.1373	$0.0027
December 31, 2003	January 15, 2004	$0.140	$0.1373	$0.0027
	Total	**$1.665**	**$1.5899**	**$0.0321**

* An amount of $0.043 per unit was allocated as taxable income in 2002

Taxable income allocated to Unitholders for 2002 is equal to the cash distributions received, plus Unitholders of record on December 31, 2002 have an additional $0.153 per Unit relating to distributions payable as at December 31, 2002. The $0.153 per unit of taxable income per Unit paid to Unitholders of record on December 31, 2002 is part of the 2002 taxable income allocation, and is not included in the 2003 taxable income allocation. Since the amount of taxable income allocated to Unitholders for 2002 is higher than the actual cash distributions received by Unitholders in 2002, there is no return of capital portion to the cash distributions.

Adjusted Cost Base

In most circumstances, the return of capital portion will reduce the Unitholder's adjusted cost base of their Focus Energy Trust Units. The adjusted cost base of the units is required in the calculation of a capital gain or capital loss (if capital property to the Unitholder) upon the disposition of the Units.

Should a Unitholder's adjusted cost base ever be reduced below zero, that negative amount is deemed to be a capital gain and the adjusted cost base is deemed to be nil. The capital gain is reported on Schedule 3 of the T1 Income Tax Return.

2003 United States Income Tax Information

- **Focus Trust Units held outside of a Qualified Retirement Plan** – For distributions relating to 2003, 100 percent of the distributions are taxable as dividends to the Unitholder for U.S. federal income tax purposes. After consulting with its tax advisors, Focus believes that its distributions should be considered "Qualified Dividends" under the Jobs and Growth Tax Relief Reconciliation Act of 2003 and should be eligible for the reduced U.S. dividend tax rate. However, the individual taxpayer's situation must be considered

before making this determination. Qualified Dividends should be reported on Line 9(b) of the IRS Form 1040, unless the facts of the U.S. individual Unitholder determines otherwise. Page 23 of the IRS 2003 Form 1040 instruction booklet provides examples of individual situations where the distributions would not be "Qualified Dividends". Where the distributions are not considered "Qualified Dividends" due to an individual's situation, the amount should be reported on Schedule B, Part II – Ordinary Dividends and Line 9 (a) of your IRS Form 1040.

For the non-taxable portion of distributions, if any, ("Non-Taxable Return of Capital"), a taxpayer must reduce the cost (or other basis) by the amount of non-taxable distributions in calculating the gain or loss on sale of Focus Units. If the amount of "Non-Taxable Return of Capital" exceeds your cost (or other basis), report the excess as a capital gain.

U.S. Unitholders are encouraged to utilize the Qualified Dividends and Capital Gain Tax Worksheet provided by the IRS to determine the amount of tax applicable.

Canadian withholding taxes that have been withheld from your distributions should be reported on Form 1116 "Foreign Tax Credit (Individual, Estate or Trust)". Information regarding the amount of Canadian tax withheld relating to 2003 distributions should be available through your investment advisor or other intermediary and is not available from Focus Energy Trust.

- **Focus Trust Units held within a Qualified Retirement Plan** – There should be no amount that is required to be reported as income on an IRS Form 1040 where the Focus Trust Units are held in a Qualified Retirement Plan.

Management and Financial Reporting Systems

The Trust's management and internal control systems are designed to provide assurance that accurate and timely internal and external information is communicated to users of that information. These systems are continually being reviewed for opportunities for enhancement.

Update on Financial Reporting and Regulatory Matters

In 2003, several changes were made in the financial reporting and regulatory environment impacting all public entities.

The Trust adopted the Canadian Institute of Chartered Accountant's (CICA) amended standard, section 3870, "Stock-based compensation and other stock based payments". This amended standard is effective for fiscal years beginning on or after January 1, 2004; however, earlier adoption is recommended. This section requires that companies measure all stock based payments using the fair value method of accounting and recognize the compensation expense in their financial statements. The Trust adopted this standard in the fourth quarter of 2003 in accordance with the transitional provisions of the standard. Per these provisions,

early adoption requires measurement and recognition of compensation expense in relation to units rights granted on or after January 1, 2003. As a result of implementation of this standard, net income of the Trust for 2003 was reduced by $245,524 and there was no impact on funds flow from operations. On a quarterly basis, net income would have been reduced by $4,023 in the first quarter, $8,825 in the second quarter, $75,918 in the third quarter and $156,758 in the fourth quarter of 2003.

The financial statements include a further discussion of this standard.

The following new and amended standards and regulatory requirements were issued in 2003 and will affect the Trust in 2004.

- *Continuous Disclosure Obligations*

  The Canadian Securities Administrators have developed new continuous disclosure requirements for reporting issuers which are contained in National Instrument 51-102 Continuous Disclosure Obligations ("NI 51-102") and are effective March 31, 2004. NI 51-102 sets out new rules and deadlines for financial statements, management's discussion and analysis ("MD&A"), annual information forms ("AIFs"), material change reporting, information circulars and other continuous disclosure matters. Another change under this instrument is that the Trust will no longer be required to mail annual and interim financial statements and MD&A to Unitholders, but rather these documents will be provided on an "as requested" basis.

  The Trust continues to assess the implications of NI 51-102 which will be implemented in 2004.

- *Asset Retirement Obligations*

  In March 2003, the CICA issued new section 3110, Asset Retirement Obligations. This new standard requires that companies recognize the liability associated with future site reclamation costs in the financial statements at the time when the liability is incurred. This liability is initially measured at fair value and subsequently adjusted for the accretion of discount and any changes in the underlying cash flows. The asset retirement cost is capitalized to the related asset and amortized into earnings over time. This new standard is effective for fiscal years beginning on or after January 1, 2004.

  The Trust is currently evaluating the impact of this standard on its financial statements and does not anticipate it will have a material impact.

- *Exchangeable Share Accounting*

  In November 2003 the CICA issued a draft EIC (D37) on "Income Trusts-Exchangeable Units". The EIC proposes that the retained interest of the exchangeable shareholders should be presented on the balance sheet as a non-controlling interest separate and distinct from Unitholders' equity. This draft EIC is currently under review and was not enacted in final form as at the date of the Trust's consolidated financial statements.

- *Oil and Gas Accounting – Full Cost*

  In September 2003 the CICA issued Accounting Guideline 16, "Oil and Gas Accounting – Full Cost" to replace Accounting Guideline 5, "Full Cost Accounting in the Oil and Gas Industry". This guideline is effective for fiscal years beginning on or after January 1, 2004.

  The guideline impacts the cost impairment test or ceiling test. The cost impairment test is a two stage test which is to be performed annually. The first stage of the test determines if the cost pool has been impaired. An impairment occurs when the carrying amount of an asset is not recoverable and exceeds its fair value. The carrying amount is not recoverable if it exceeds the sum of the undiscounted cash flows from proved reserves plus unproved costs using management's best estimate of future prices. The second stage of the test involves measurement of the impairment. The impairment is measured as the amount by which the carrying amount of capitalized assets exceeds the future discounted cash flows from proved plus probable reserves. The discount rate used is the company's risk free rate. The guideline requires disclosure of future prices used in the measurement of impairment.

  The Trust is currently evaluating the impact of this standard on its financial statements and does not anticipate it will have a material impact.

- *Hedging Relationships*

  In December 2001 the CICA issued Accounting Guideline 13, "Hedging Relationships" which deals with the identification, designation, documentation and measurement of effectiveness of hedging relationships for the purposes of applying hedge accounting. It also establishes conditions for applying or discontinuing hedge accounting. This guideline is effective for fiscal years beginning on or after July 1, 2003.

  The Trust has formally documented all transactions and they were determined to meet the criteria of effective hedges as at December 31, 2003.

- *Variable Interest Entities*

  In June 2003 the CICA issued Accounting Guideline 15, "Consolidation of Variable Interest Entities" which deals with the consolidation of entities that are subject to control on a basis other than ownership of voting interests. This guideline is effective for annual and interim periods beginning on or after November 1, 2004.

  The Trust has assessed that this new guideline is not applicable based on the current structure of the Trust.

Quarterly Information

Quarter Ended ($ thousands except per unit amounts)	31-Dec 2003	30-Sep 2003	30-Jun 2003	31-Mar 2003	31-Dec 2002	30-Sep 2002	30-Jun 2002	31-Mar 2002
Total revenues	$27,429	$27,272	$30,487	$29,394	$24,282	$25,869	$35,877	$28,403
Net income	$10,456	$10,608	$12,449	$7,959	8,554	$8,713	$6,793	$9,256
Per unit								
- basic	$0.33	$0.33	$0.43	$0.27	$0.30	$0.31	$0.24	$0.34
- diluted	$0.33	$0.33	$0.43	$0.27	$0.30	$0.30	$0.24	$0.32

The above table highlights Focus' quarterly performance for the years ended December 31, 2003 and 2002. As Focus is the successor organization to Storm Energy Inc., information for the first three quarters of 2002 includes the operations of Storm Energy Inc. for the period January 1, 2002 to August 23, 2002 prior to the reorganization.

Assessment of Business Risks

Following are the primary risks associated with the business of the Trust. These risks are similar to those affecting others in the conventional oil and gas income trust sector. The Trust's financial position, results of operations and distributions to Unitholders are directly impacted by these factors.

1) operational risk associated with the production of oil and natural gas;
2) reserve risk in respect to the quantity and quality of recoverable reserves;
3) market risk relating to the availability of transportation systems to move the product to market;
4) commodity risk as crude oil and natural gas prices fluctuate due to market forces;
5) financial risk such as the Canadian / US dollar exchange rate, interest rates and debt service obligations;
6) environmental and safety risk associated with well operations and production facilities;
7) changing government regulations relating to royalty legislation, income tax laws, incentive programs, operating practices and environmental protection relating to the oil and gas industry and the income trust sector;
8) risk of liability to Unitholders since there is no statutory protection for Unitholders from liabilities of the Trust.

Focus seeks to mitigate these risks by:

1) acquiring mature properties to reduce technical uncertainty;
2) acquiring long life reserves to ensure more stable production and to reduce the economic risks associated with commodity prices cycles;
3) maintaining a low-cost structure to maximize product netbacks and reduce impact of commodity price cycles;
4) diversifying properties to mitigate individual property and well risk;
5) maintaining a product mix to balance exposure to commodity prices;
6) conducting rigorous reviews of all property acquisitions;
7) monitoring pricing trends and developing a mix of contractual arrangements for the marketing of products with creditworthy counterparties;
8) maintaining a hedging program to hedge commodity prices and foreign exchange currency rates with creditworthy counterparties;
9) ensuring strong third party-operators for non-operated properties;
10) adhering to the Trust's safety program and keeping abreast of current operating best practices;
11) keeping informed of proposed change in regulations and laws to properly respond to and plan for the effects that these changes may have on our operations;
12) carrying insurance to cover losses and business interruption; and
13) establishing and building cash resources to fund future abandonment and site restoration costs.

Outlook

The Trust's operational results and financial condition will be dependent on the prices received for oil and natural gas production. Oil and natural gas prices have fluctuated widely during recent years and are determined by demand and supply factors, including weather and general economic conditions as well as conditions in other oil and natural gas regions.

The following chart summarizes Focus' 2004 outlook. This forecast includes the acquisition at Tommy Lakes April 1, 2004. No other acquisitions are assumed for the purposes of these forecasts.

In 2004, Focus will continue its active drilling and development program on the significant development opportunities on its major properties. It is anticipated that these development opportunities will maintain production by offsetting production declines.

Focus does not attempt to forecast commodity prices, and as a result, we do not forecast funds flow from operations or future cash distributions to Unitholders.

Summary of 2004 Expectations (1)	
Average annual production	10,000 BOE/d
Weighting to natural gas	73%
Production expenses per BOE	$ 3.40
G&A expenses per BOE (2)	$1.30
Capital expenditures – field	$20.6 million
Payout ratio	75% – 85%
Approximate taxable portion of distributions	100%
Net debt / Funds from operations	Under 1x

(1) With acquisition at Tommy Lakes April 1, 2004
(2) Including cash and non-cash components

The table below shows the potential impact on the Trust's 2004 funds flow from operations (after hedging) resulting from changes to the business environment or operations.

		Change to Funds Flow	
	Change	$000's	$ / Unit
Business Environment			
Price per barrel of crude oil ($US WTI)	$ 1.00	510	0.014
Price per mcf of natural gas ($CDN AECO)	$ 0.25	1,800	0.050
US/CDN exchange rate	$ 0.01	725	0.020
Interest rate on debt	1%	450	0.012
Operations			
Oil production - bbls/d	100	1,060	0.030
Gas production - mcf/d	1,000	1,670	0.046
Operating expenses ($ per BOE)	$ 0.25	912	0.025
Cash G&A expenses ($ per BOE)	$ 0.25	912	0.025

Focus is committed to increasing the long-term value of the Trust to Unitholders. The following goals are the foundation of our commitment to value creation:

- Maximize the value of existing assets;
- Attract and retain the best value creation team in the business;
- Pursue quality acquisitions that are strategic and accretive;
- Protect margins and improve profitability;
- Surface value through operational expertise and control; and
- Maintain financial flexibility and strength.

Management's Responsibility

Management is responsible for the preparation of the accompanying consolidated financial statements and for the consistency therewith of all other financial and operating data. The consolidated financial statements have been prepared in accordance with the accounting policies detailed in the notes thereto. In Management's opinion, the consolidated financial statements are in accordance with Canadian generally accepted accounting principles and have been prepared within acceptable limits of materiality.

Management maintains a system of internal controls to provide reasonable assurance that all assets are safeguarded, transactions are appropriately authorized and to facilitate the preparation of relevant, reliable and timely information. Where estimates are used in the preparation of these financial statements, management has ensured that careful judgement has been made and that these estimates are reasonable, based on all information known at the time the estimates are made.

Independent auditors appointed by the Trustee have examined and expressed their opinion on the consolidated financial statements of the Trust. The Audit Committee, consisting of independent directors of FET Resources Ltd., has reviewed these consolidated financial statements with management and the auditors, and has recommended them to the Board of Directors for approval. The Board has approved the consolidated financial statements of the Trust.

Derek W. Evans
President and Chief Executive Officer
March 24, 2004

William D. Ostlund
Vice President, Finance and Chief Financial Officer

Auditor's Report

To the Unitholders of Focus Energy Trust:

We have audited the consolidated balance sheet of Focus Energy Trust as at December 31, 2003 and the consolidated statements of income and accumulated income and cash flows for the year then ended. These financial statements are the responsibility of the Trust's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Trust as at December 31, 2003 and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

The financial statements for the year ended December 31, 2002 were reported on by another firm of chartered accountants who expressed an opinion without reservation in their audit report dated February 28, 2003.

KPMG LLP
Chartered Accountants

Calgary, Alberta
March 24, 2004

Consolidated Balance Sheets

	December 31, 2003	December 31, 2002 (Notes 1 and 3)
ASSETS		
Current assets		
Cash and cash equivalents	$ –	$ 14,705,034
Accounts receivable [note 14]	20,043,512	24,485,558
Prepaid expenses	1,092,559	1,081,605
	21,136,071	40,272,197
Petroleum and natural gas properties and equipment [note 4]	170,904,914	158,299,726
Reclamation fund [note 5]	1,030,000	–
	$193,070,985	$ 198,571,923
LIABILITIES		
Current		
Accounts payable and accrued liabilities [note 14]	$ 20,515,765	$ 19,805,189
Cash distributions payable	3,924,783	3,846,991
Commodity contract	–	1,353,067
	24,440,548	25,005,247
long-term debt [note 6]	21,336,532	51,801,000
Provision for site restoration and abandonment [note 4]	3,083,021	2,343,734
Future income taxes [note 13]	41,816,843	42,633,486
	90,676,944	121,783,467
UNITHOLDERS' EQUITY		
Unitholders' capital [note 7]	63,267,421	33,908,902
Exchangeable shares [note 7]	5,160,995	9,628,379
Contributed surplus [note 8]	245,524	–
Accumulated income	85,820,667	44,348,355
Accumulated cash distributions	(52,100,566)	(11,097,180)
	102,394,041	76,788,456
Commitments and contingencies [note 15]		
Subsequent events [note 16]		
	$193,070,985	$ 198,571,923

See Notes to Consolidated Financial Statements

Approval on behalf of the Board:

STUART G. CLARK
Director

GERALD A. ROMANZIN
Director

Consolidated Statements of Income and Accumulated Income

	Years Ended December 31, 2003	2002 (Note 1)
Revenues		
Production revenue	$ 111,832,343	$ 114,593,548
Royalties	(30,789,864)	(28,090,717)
Alberta Royalty Tax Credit	287,512	389,541
Facility income	2,611,767	1,574,612
Interest income	64,128	176,715
	84,005,886	88,643,699
Expenses		
Production	10,590,468	12,975,580
Technical Services Agreement [note 3]	2,100,000	1,501,613
General and administrative	3,627,275	3,100,384
Interest and financing	1,386,761	2,472,579
Depletion and depreciation	24,420,714	26,720,714
Provision for site restoration and abandonment	1,000,633	1,225,926
Reorganization expenses [note 3]	–	12,717,078
	43,125,851	60,713,874
Income before income and other taxes	40,880,035	27,929,825
Income and other taxes [note 13]		
Future income tax expense (reduction)	(816,643)	6,673,206
Current and large corporations tax	224,366	2,051,378
	(592,277)	8,724,584
Net income for the period	41,472,312	19,205,241
Transfer of assets and liabilities pursuant to Plan of Arrangement [note 3]	–	(26,532,976)
Accumulated income, beginning of period	44,348,355	51,676,090
Accumulated income, end of period	$ 85,820,667	$ 44,348,355
Net income per Unit [note 12]		
Basic and diluted	$ 1.36	$ 0.68

See Notes to Consolidated Financial Statements

Consolidated Statements of Cash Flows

	Years Ended December 31, 2003	2002 (Note 1)
Operating activities		
Net income for the period	$ 41,472,312	$ 19,205,241
Add non-cash items:		
Non-cash general and administrative expenses	1,084,483	277,002
Unrealized (gain) loss on commodity contract	(1,353,067)	1,353,067
Depletion and depreciation	24,420,714	26,720,714
Provision for site restoration and abandonment	1,000,633	1,225,926
Future income tax expense (reduction)	(816,643)	6,673,206
Funds flow from operations	65,808,432	55,455,156
Actual site restoration paid	(261,346)	(6,947)
Net change in non-cash working capital items	6,145,327	(12,514,656)
	71,692,412	42,933,553
Financing activities		
Proceeds from issue of Trust Units (net of costs)	23,891,651	–
Issue of Exchangeable shares	–	999,990
Proceeds from exercise of stock options	158,048	3,019,428
Increase (decrease) in long-term debt	(30,464,468)	21,084,490
Cash distributions	(40,925,594)	(7,250,189)
	(47,340,363)	17,853,719
Investing activities		
Petroleum and natural gas properties and equipment additions	(16,809,155)	(40,139,989)
Acquisitions	(22,175,416)	–
Proceeds on disposal of petroleum and natural gas properties and equipment	1,958,669	–
Reclamation fund contributions	(1,030,000)	–
Net change in non-cash working capital items	(1,001,181)	(5,942,249)
	(39,057,083)	(46,082,238)
Increase (decrease) in cash and cash equivalents during the period	(14,705,034)	14,705,034
Cash and cash equivalents, beginning of period	14,705,034	–
Cash and cash equivalents, end of period	$ –	$ 14,705,034

See Notes to Consolidated Financial Statements

1. STRUCTURE OF THE TRUST AND BASIS OF PRESENTATION

Focus Energy Trust (the "Trust") was established on August 23, 2002 under a Plan of Arrangement involving the Trust, Storm Energy Inc., FET Resources Ltd., and Storm Energy Ltd. The Trust is an open-end unincorporated investment trust governed by the laws of the Province of Alberta and created pursuant to a trust indenture (the "Trust Indenture"). Valiant Trust Company has been appointed Trustee under the Trust Indenture. The beneficiaries of the Trust are the holders of the Trust Units (the "Unitholders").

FET Resources Ltd. (the "Company") is a wholly-owned subsidiary of the Trust. Under the Plan of Arrangement, the Company became the successor company to Storm Energy Inc. through amalgamation on August 23, 2002. The Company is actively engaged in the business of oil and natural gas exploitation, development, acquisition and production.

Prior to the implementation of the Plan of Arrangement on August 23, 2002, the consolidated financial statements included the accounts of the Storm Energy Inc. and its subsidiaries. After giving effect to the Plan of Arrangement, the consolidated financial statements have been prepared on a continuity of interests basis which recognizes the Trust as the successor entity to Storm Energy Inc. The consolidated financial statements of Focus Energy Trust include the accounts of the Trust, its wholly-owned subsidiaries (the Company and FET Gas Production Ltd.), and its share of a partnership.

2. SUMMARY OF ACCOUNTING POLICIES

The consolidated financial statements have been prepared by management in accordance with Canadian generally accepted accounting principles ("GAAP"). The preparation of these consolidated financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingencies at the date of the financial statements, and revenues and expenses during the reporting period. Correspondingly, actual results could differ from estimated amounts. These consolidated financial statements have, in management's opinion, been properly prepared within reasonable limits of materiality and within the framework of the accounting policies summarized below.

In particular, the amounts recorded for depletion and depreciation of the petroleum and natural gas properties and equipment and for site restoration and abandonment are based on estimates of reserves and future costs. The ceiling test is based on estimates of proved reserves, production rates, oil and natural gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the impact on the consolidated financial statements of future periods could be material.

a) Principles of Consolidation

The consolidated financial statements include the accounts of the Trust, its wholly-owned subsidiaries, and its share of a partnership. All inter-entity transactions and balances have been eliminated.

b) Petroleum and Natural Gas Properties and Equipment

The Trust follows the full cost method of accounting for petroleum and natural gas properties, whereby all costs of acquiring petroleum and natural gas properties and related development costs, whether productive or unproductive, are capitalized and accumulated in one Canadian cost centre. Such costs include acquisition, drilling, geological, geophysical, and equipment costs and overhead expenses related to the properties and development activities. Costs of acquiring and evaluating unproved properties are excluded from depletion calculations until it is determined in the period that proved reserves are attributable to the properties or impairment has occurred.

Maintenance and repairs are charged against income, and renewals and enhancements which extend the economic life of the properties and equipment are capitalized. Gains or losses are not recognized upon disposition of petroleum and natural gas properties unless crediting the proceeds against accumulated costs would result in a change in the rate of depletion of 20 percent or more.

Depletion of petroleum and natural gas properties and depreciation of equipment are provided for using the unit-of-production method based on estimated proved petroleum and natural gas reserves, before royalties, as determined by independent engineers calculated in accordance with National Instrument 51-101. Production and reserves of natural gas are converted to equivalent barrels of crude oil based on the energy equivalent conversion ratio of six thousand cubic feet of natural gas to one barrel of oil. The depletion and depreciation cost base includes total capitalized costs, less prior depletion and depreciation charges, less costs of unproved properties, less the estimated future net realizable value of production equipment and facilities, plus provision for future development costs of proved undeveloped reserves.

c) Ceiling Test

The Trust places a limit on the aggregate carrying value of petroleum and natural gas properties and equipment, which may be amortized against revenues of future periods (the "ceiling test"). The ceiling test is a cost recovery test whereby the capitalized costs less accumulated depletion and depreciation, future site restoration and abandonment and future income tax liabilities are limited to an amount equal to the estimated undiscounted future net revenues from proved reserves less estimated recurring general and administrative expenses, future site reclamation and abandonment costs, future financing costs and income taxes. Costs and prices at the balance sheet date are used. Any costs carried on the balance sheet date in excess of the ceiling test limitation are charged to income.

d) Provision for Site Restoration and Abandonment

Provisions for future site restoration and abandonment are calculated on the unit-of-production basis over the life of the oil and gas properties based on total estimated proved reserves. The estimate made by management in consultation with the Trust's engineers, includes the cost of equipment removal and environmental clean up in accordance with current cost, anticipated methods, existing legislation and industry practice. The period change is expensed and actual expenditures are charged against the liability as incurred.

e) Financial Instruments

The Trust uses financial instruments to reduce its exposure to fluctuations in commodity prices and foreign exchange rates. The Trust's policy is not to use financial instruments for speculative or trading purposes. Gains and losses on contracts which constitute effective hedges are recognized in production income at the time of sale of the related production. Financial instruments which do not qualify as hedges are recorded on a mark-to-market basis at the balance sheet date with the resulting gains or losses being taken into income in the period.

f) Income Taxes

Income taxes are calculated using the liability method of accounting for income taxes. Under this method, income tax liabilities and assets are recognized for the estimated tax consequences attributable to differences between the amounts reported in the consolidated financial statements of the Trust and their respective tax base, using substantively enacted income tax rates. The effect of a change in income tax rates on future tax liabilities and assets is recognized in income in the period in which the change occurs. Temporary differences arising on acquisitions result in future income tax assets and liabilities.

The Trust is a taxable entity under the Income Tax Act (Canada) and is taxable only on income that is not distributed or distributable to the Unitholders. As the Trust allocates all of its taxable income to the Unitholders in accordance with the Trust Indenture, and meets the requirements of the Income Tax Act (Canada) applicable to the Trust, no provision for income tax expense has been made in the Trust.

In the Trust structure, payments are made between the Company and the Trust which result in the transferring of taxable income from the Company to individual Unitholders. These payments may reduce future income tax liabilities previously recorded by the Company which would be recognized as a recovery of income tax in the period incurred.

g) Unit-Based Compensation Plan

The Trust has a unit-based compensation plan (the "Plan") for employees, directors and consultants of the Trust and its subsidiaries which are described in Note 8. Compensation expense associated with rights granted under the Plan is deferred and recognized in income over the vesting period of the Plan with a corresponding increase or decrease in contributed surplus. Compensation expense is based on the fair value of the unit-based compensation at the date of grant using a Black Scholes option pricing model. The fair value method has been adopted prospectively for 2003 rights granted. The pro forma impact for rights granted for the period from August 23, 2002 to December 31, 2002 using the fair value method is disclosed in Note 8.

Consideration paid upon the exercise of the rights together with the amount previously recognized in contributed surplus is recorded as an increase in unitholders' capital.

The Trust has not incorporated an estimated forfeiture rate for rights that will not vest, rather, the Trust accounts for actual forfeitures as they occur.

h) Per Unit Amounts

Net income per Unit is calculated using the weighted average number of Units (or common shares to August 23, 2002) outstanding during the year, including the weighted average number of Exchangeable Shares outstanding converted at the exchange ratio at the end of each month. Diluted net income per Unit is calculated using the treasury stock method to determine the dilutive effect of unit based compensation. The treasury stock method assumes that the proceeds received from the exercise of "in the money" Trust Unit rights are used to repurchase Units at the average market rate during the period. The weighted average number of Units outstanding is then adjusted by the net change.

i) Revenue Recognition

Revenue associated with sales of crude oil, natural gas, and natural gas liquids is recognized when title passes to the purchaser, normally at the pipeline delivery point for natural gas and at the wellhead for crude oil.

j) Joint Operations

Certain of the Trust's exploration and production activities are conducted jointly with others through unincorporated joint ventures. The accounts of the Trust reflect its proportionate interest in such activities.

k) Cash and Cash Equivalents

The Trust considers all highly liquid investments with a maturity of three months or less at the time of purchase to be cash equivalents. These cash equivalents consist primarily of funds on deposit for various terms. Cash and cash equivalents are stated at cost which approximates fair value.

l) Foreign Currency Translation

Monetary assets and liabilities denominated in a foreign currency are translated at the rate of exchange in effect at the balance sheet date. Revenues and expenses are translated at the monthly average rates of exchange. Translation gains and losses are included in income in the period in which they arise.

m) Comparative Figures

Certain of the comparative figures have been reclassified to conform to the current year's presentation.

3. TRANSFER OF ASSETS AND LIABILITIES PURSUANT TO PLAN OF ARRANGEMENT

Under the Plan of Arrangement, the Company transferred to Storm Energy Ltd. certain assets, being producing and exploratory oil and gas properties, administrative assets and working capital, and an allocation of long-term debt. As this was a related party transaction, assets and liabilities were transferred at book value. Details are as follows:

Petroleum and natural gas properties and equipment	$	**49,739,821**
Office furniture and equipment		**348,714**
Leasehold improvements		**37,454**
Net working capital		**1,575,566**
Future income tax asset		**191,551**
Total assets transferred		**51,893,106**
long-term debt		**24,292,399**
Provision for site restoration and abandonment		**1,067,731**
Net assets transferred and reduction in retained earnings	$	**26,532,976**

Associated with the Plan of Arrangement, the Company recorded reorganization costs of $12.7 million, with $9.6 million related to the cancellation of stock options, and advisory and other costs of $3.1 million.

4. PETROLEUM AND NATURAL GAS PROPERTIES AND EQUIPMENT

		2003		2002
Petroleum and natural gas properties and equipment, at cost	$	**284,708,698**	$	247,682,796
Accumulated depletion and depreciation		**(113,803,784)**		(89,383,070)
Petroleum and natural gas properties and equipment, at cost, net	$	**170,904,914**	$	158,299,726

The calculation of depletion and depreciation in 2003 included an estimate of $28.4 million (2002 – $28.5 million) for future development costs associated with proved undeveloped reserves. Unproved property costs of $1.8 million (2002 – nil) and estimated net realizable value of production equipment and facilities of $12.6 million (2002 – nil) were excluded from the depletion calculation.

The ceiling test calculation as at December 31, 2003 indicated that the net recoverable amount from proved reserves exceeded the net carrying value of the petroleum and natural gas properties and equipment. The ceiling test is a cost recovery test and is not intended to result in an estimate of fair market value. The prices used for the ceiling test were based on commodity prices as at the measurement date of December 31, 2003 being $40.28 per barrel of crude oil (2002 – $44.98), $6.72 per mcf of natural gas (2002 – $5.56), and $36.25 per barrel of natural gas liquids (2002 – $38.04).

As at December 31, 2003, the Trust's estimated future site restoration and abandonment costs to be accrued over the life of the remaining proved reserves is $18,337,000 (2002 – $6,885,000). Of this amount, $3,083,020 has been accrued as an accumulated liability on the consolidated balance sheet as at December 31, 2003 (2002 – $2,343,734).

5. RECLAMATION FUND

		2003		2002
Balance as at January 1	$	–	$	–
Contributions	$	1,030,000	$	–
Balance as at December 31	$	1,030,000	$	–

A reclamation fund was established to fund the payment of environmental and site reclamation costs. Annual contributions will be made to the reclamation fund such that the currently estimated future environmental and site reclamation costs will be funded after 20 years. Interest earned will form part of the reclamation fund. The Company may use the reclamation fund for purposes of funding its' environmental and site reclamation costs. The reclamation fund is held on deposit at a Canadian financial institution.

6. LONG-TERM DEBT

The Company has a revolving term credit facility with a Canadian financial institution. The Company has $70 million available under this facility. At December 31, 2003, the available borrowings under this facility were reduced by an $800,000 letter of credit. Advances bear interest at the bank's prime rate, bankers' acceptance rates plus stamping fees, or U.S. labor rates plus applicable margins, depending on the form of borrowing by the Company. The facility is subject to an annual review by the bank and if certain conditions are not met the facility becomes a two year term loan with the first repayment due within 366 days. No current payments are required. The loan facility is secured by a floating charge debenture in the amount of $125 million covering all of the assets of the Company and a general security agreement.

Subsequent to December 31, 2003, the Company closed a $70 million revolving syndicated credit facility among four financial institutions with an extendible 364 day revolving period and a one year amortization period. The loan facility is secured by a floating charge debenture in the amount of $300 million covering all of the assets of the company and a general security agreement. The Company also has a $10 million demand operating line of credit.

Advances bear interest at the bank's prime rate, bankers' acceptance rates plus stamping fees, or U.S. labor rates plus applicable margins depending on the form of borrowing by the Company. Stamping fees and margins vary from zero percent to 1.50 percent dependent upon financial statement ratios and type of borrowing.

The credit facility will revolve until May 2004, whereupon it may be renewed for a further 364 day term subject to review by the lenders. If not extended, principal payments will commence after expiry of the revolving period and will consist of three quarterly payments of five percent and the remaining 85 percent at the end of the term.

7. UNITHOLDERS' CAPITAL AND EXCHANGEABLE SHARES

Pursuant to the Plan of Arrangement, 20,884,039 Trust Units and 7,706,263 Exchangeable Shares were issued on August 23, 2002 upon the cancellation of all outstanding common shares of Storm Energy Inc. and 145,984 Exchangeable Shares were purchased by three officers of the Trust.

An unlimited number of Trust Units may be issued pursuant to the Trust Indenture. Each Trust Unit entitles the holder to one vote at any meeting of the Unitholders and represents an equal fractional undivided beneficial interest in any distribution from the Trust and in any net assets in the event of termination or winding-up of the Trust. The Trust Units are redeemable at the option of the Unitholder, up to a maximum of $250,000 per annum. This limitation may be waived at the discretion of the Company.

Trust Units of Focus Energy Trust (including conversion of Exchangeable Shares)	Number of Units		Consideration	
	2003	2002	2003	2002
Trust Units outstanding (see (a) below)	28,034,233	22,804,905	$63,267,421	$33,908,902
Trust Units issuable on conversion of Exchangeable Shares (i) (see (b) below)	3,788,258	6,160,621	5,160,995	9,628,379
Balance as at December 31	31,822,491	28,965,526	$68,428,416	$43,537,281

i. *The exchange ratio at December 31, 2003 was 1.16718 (December 31, 2002 - 1.03291) Trust Units for each Exchangeable Share.*

(a) Trust Units of Focus Energy Trust	Number of Units		Consideration	
	2003	2002	2003	2002
Balance as at January 1	22,804,905	–	$33,908,902	$ –
Issued pursuant to Plan of Arrangement (i)	–	20,884,039	–	30,970,217
Issued on conversion of Exchangeable Shares (ii)	3,037,076	1,907,393	4,467,384	2,799,700
Issued pursuant to the Executive Bonus Plan (iii)	71,752	13,473	841,434	138,985
Issued for Cash Trust Units (iv)	2,100,000	–	25,410,000	–
Trust Unit Issue Expenses	–	–	(1,518,347)	–
Exercise of Unit Appreciation Rights	20,500	–	158,048	–
Balance as at December 31	28,034,233	22,804,905	$63,267,421	$33,908,902

i. *Issued August 23, 2002 pursuant to the Plan of Arrangement and recorded at the book value of the Storm Energy Inc. common shares*

ii. *Issued on conversion of Exchangeable Shares to Trust Units with the consideration recorded being equal to the book value of the Exchangeable Shares exchanged*

iii. *Pursuant to the Executive Bonus Plan, 50 percent of all amounts due under such plan are payable through the issuance of Trust Units priced at the five day weighted average trading price for the last five trading days of the month for which the bonus relates.*

iv. *Issued for cash on June 25, 2003.*

(b) Exchangeable Shares of FET Resources Ltd.	Number of Shares		Consideration	
	2003	2002	2003	2002
Balance as at January 1	5,964,335	–	$9,628,379	$ –
Issued pursuant to Plan of Arrangement (i)	–	7,706,263	–	11,428,089
Issued for cash(ii)	–	145,984	–	999,990
Exchanged for Trust Units(iii)	(2,718,685)	(1,887,912)	(4,467,384)	(2,799,700)
Balance as at December 31	3,245,650	5,964,335	$5,160,995	$9,628,379

i. *Issued August 23, 2002 pursuant to the Plan of Arrangement and recorded at the book value of the Storm Energy Inc. common shares*

ii. *Purchase by three officers of the Trust pursuant to the Plan of Arrangement*

iii. *Cancellation on conversion to Trust Units with the consideration recorded being equal to the book value of the Exchangeable Shares exchanged*

The Exchangeable shares of FET Resources Ltd. are convertible at any time into Trust Units (at the option of the holder) based on the exchange ratio. The exchange ratio is increased monthly based on the cash distribution paid on the Trust Units divided by the ten day weighted average Unit price preceding the record date. During the period of January 1 to December 31, 2003, a total of 2,718,685 Exchangeable Shares were converted into 3,037,076 Trust Units at exchange ratios prevailing at the time. The exchange ratio at the time of issuance on August 23, 2002 was one Trust Unit for each Exchangeable Share. At December 31, 2003, the exchange ratio was 1.16718 Trust Units for each Exchangeable Share. Cash distributions are not paid on the Exchangeable shares. On the tenth anniversary of the issuance of the Exchangeable Shares, subject to extension of such date by the Board of Directors of the Company, the Exchangeable Shares will be redeemed for Trust Units at a price equal to the value of that number of Trust Units based on the exchange ratio as at the last business day prior to the redemption date. The Exchangeable Shares of FET Resources Ltd. are listed for trading on the Toronto Stock Exchange under the symbol FTX.

(c) **Common Shares of Storm Energy Inc.**	Number of Shares		Consideration
Balance as at December 31, 2001	27,782,008	$	39,378,878
Issued upon exercise of stock options	808,294		3,019,428
Balance August 22, 2002 prior to Plan of Arrangement	28,590,302		42,398,306
Trust Units issued	(20,884,039)		(30,970,217)
Exchangeable Shares issued	(7,706,263)		(11,428,089)
	nil	$	nil

Pursuant to the Plan of Arrangement, shareholders of Storm Energy Inc. received one Unit in Focus Energy Trust or one Exchangeable share in FET Resources Ltd., and one share in a new public exploration and production company, Storm Energy Ltd., for each common share held.

8. TRUST UNIT RIGHTS PLAN

The Trust Unit Rights Plan (the "Plan") was established August 23, 2002 as part of the Plan of Arrangement. The Trust may grant rights to employees, directors, consultants and other service providers of the Trust and any of its subsidiaries. The Trust is authorized to grant up to 1,500,000 rights, but the number of Units reserved for issuance upon the exercise of Rights shall not at any time exceed 5 percent of the aggregate number of issued and outstanding Units of the Trust and including the number of Units which may be issued on the exchange of the outstanding Exchangeable Shares.

The initial exercise price of rights granted under the Plan is equal to the weighted average of the closing price of the Trust Units on the immediately preceding five trading days. The exercise price per right is calculated by deducting from the grant price the aggregate of all distributions, on a per Unit basis, made by the Trust after the grant date which represent a return of more than 0.833 percent of the Trust's recorded cost of capital assets less depletion, depreciation and amortization charges and any future income tax liability associated with such capital assets at the end of each month. Provided this test is met, then the entire amount of the distribution is deducted from the grant price. The rights have a life of five years, and vest equally over a four year period commencing on the first anniversary of the grant.

	Number of Rights		Weighted Average Exercise Price - $	
	2003	2002	2003	2002
Balance as at January 1	320,000	–	$9.39	–
Granted	376,000	320,000	$12.19	$9.68
Exercised	(20,500)	–	$7.71	–
Cancelled	(10,000)	–	$12.08	–
Before reduction of exercise price	665,500	320,000	$11.07	$9.68
Reduction of exercise price	–	–	(1.33)	(0.29)
Balance as at December 31	665,500	320,000	$9.74	$9.39

A summary of the plan as at December 21, 2003 is as follows:

Exercise Price at Grant Date	Adjusted Exercise Price	Number of Rights Outstanding	Remaining Contractual Life of Rights (years)	Number of Rights
$ 9.62	$ 7.655	259,500	3.69	49,500
10.10	8.465	40,000	3.97	10,000
10.87	9.480	40,000	4.12	–
11.54	10.420	6,000	4.35	–
12.08	11.240	254,000	4.52	–
14.26	13.700	8,000	4.67	–
13.61	13.050	5,000	4.71	–
13.38	12.960	50,000	4.76	–
13.33	13.050	3,000	4.81	–
$ 11.07	$ 9.740	665,500	4.16	59,500

The Trust has prospectively adopted the fair value method for 2003 rights granted. The Trust has recorded non-cash compensation expense and contributed surplus of $245,524 for the year ended December 31, 2003. This amount is calculated based on rights issued subsequent to January 1, 2003 of 376,000 rights.

Had the Trust used the fair value method for rights granted between August 23, 2002 and December 31, 2002 pro forma net income would have decreased by $136,758 (2002 - $37,154).

Pro Forma Results	2003	2002
Net income as reported	$ 41,472,312	$ 19,205,241
Less: compensation expense for rights issued in 2002	(136,758)	(37,154)
Pro forma net income	$ 41,335,554	$ 19,168,087
Net income per Trust Unit – basic		
As reported	$ 1.36	$ 0.68
Pro forma	$ 1.36	$ 0.68
Net income per Trust Unit – diluted		
As reported	$ 1.36	$ 0.68
Pro forma	$ 1.35	$ 0.68

The fair value of rights granted in 2003 was estimated using a modified Black Scholes option pricing model with the following weighted average assumptions: risk-free interest rate of 4.23%, volatility of 20%, life of five years and a dividend yield rate of 11%. Users are cautioned that the assumptions made are estimates of future events and actual results could differ materially from those estimated.

9. CASH DISTRIBUTIONS PAYABLE

The Trust has net income for each year which includes all interest income from the Company, and other income, which accrues to the Trust to the end of the year. Under the Trust Indenture, taxable income of the Trust for each year will be paid or payable by way of cash distributions to the Unitholders.

The taxable income of the Trust includes a deduction for the allocation of taxable income to Unitholders, which is paid or becomes payable in the year. The Trust Indenture provides that an amount at least equal to the taxable income of the Trust must be paid or payable each year to Unitholders in order to reduce the Trust's taxable income to zero. Such taxable income relating to the payable amount is allocated to Unitholders of record at the end of the year, and each Unitholder receives a pro rata share of the payable amount.

10. FINANCIAL INSTRUMENTS

The Company's financial instruments included in the balance sheet are comprised of accounts receivable, other receivables, accounts payable and accrued liabilities and bank debt.

Credit risk:
The Company's accounts receivable are due from a diverse group of customers and as such are subject to normal credit risks.

Interest rate risk:
The Company is also exposed to interest rate risk to the extent that long-term debt is at a floating rate of interest.

Fair values:
The fair values of short term financial instruments, being accounts receivable, accounts payable and accrued liabilities and cash distributions payable approximate their carrying values due to their short term to maturity. The fair value of long-term debt approximates its carrying value due to the floating interest rate and the revolving nature of the obligation.

The following financial contracts were outstanding as at December 31, 2003. Settlement of these contracts, which have no book value, would have resulted in a net payment by the Trust of $1,128,949.

Financial Contracts	Daily Quantity	Contract Price	Price Index	Term
Crude oil – fixed price	500 bbls	$ 41.80 CDN	WTI	September 2003 – August 2004
	900 bbls	$ 35.63 CDN	WTI	September 2003 – December 2004
Natural gas – costless collar	6,420 GJ	$ 5.75-$8.03 CDN	AECO	November 2003 – March 2004

11. PHYSICAL SALES CONTRACTS

In addition to the financial contracts described above, the following physical contracts were outstanding at the date of writing. Settlement of these contracts, which have no book value, would have resulted in a net payment to the Trust of approximately $391,266.

Physical Contracts	Daily Quantity	Contract Price	Price Index	Term
Natural gas – fixed price	5,000 MMBTU	$ 8.21 CDN	Sumas	November 2003 – March 2004
	5,000 GJ	$ 7.21 CDN	Stn.2, B.C.	November 2003 – March 2004
	5,000 GJ	$ 6.11 CDN	Stn.2, B.C.	November 2003 – October 2004
	6,000 GJ	$ 5.20 CDN	Stn.2, B.C.	April 2004 – October 2004
	7,000 GJ	$ 5.13 CDN	Stn.2, B.C.	April 2004 – October 2004
	6,000 GJ	$ 5.68 CDN	Stn.2, B.C.	April 2004 – October 2004*
	5,000 GJ	$ 6.47 CDN	Stn.2, B.C.	November 2004 – March 2005*

* Contracts entered into subsequent to December 31, 2003

12. PER UNIT AMOUNTS AND SUPPLEMENTARY CASH FLOW INFORMATION

Basic per unit calculations are based on the weighted average number of Trust Units (common shares prior to August 23, 2002) outstanding. Diluted calculations include additional Trust Units for the dilutive impact of rights outstanding pursuant to the Rights Plan.

Basic per unit calculations are based on the weighted average number of Trust Units outstanding in 2003 of 30,493,373 (2002 of 28,799,795 for the period August 23 to December 31 and 28,210,245 Trust Units or common shares for the year ended December 31, 2002) which includes outstanding Exchangeable Shares converted at the year-end exchange ratio.

Diluted calculations include additional Trust Units in 2003 of 129,990 (2002 of 8,764 for the period August 23 to December 31 and 3,145 for the year ended December 31, 2002) for the dilutive impact of the Rights Plan. There were no adjustments to net income in calculating dilutive per unit amounts.

Supplementary cash flow information

	2003	2002
Interest paid	**$ 1,345,300**	$ 2,349,829
Interest received	**18,003**	176,715
Taxes paid	**(862,688)**	882,382
Cash distributions paid	**40,925,594**	7,250,188

13. INCOME TAXES

In 2003, Royal Assent was received legislating the reduction of the general corporate income tax rate on income from resource activities from 28 percent to 21 percent and for the elimination of the existing 25 percent resource allowance deduction and introduced the deductibility of actual provincial and other Crown royalties paid all over a five year period. As a result of these changes, as well as a reduction in the Alberta corporate income tax rate from 13 percent to 12.5%, the expected future income tax rate is 37 percent compared to 42 percent at December 31, 2002.

As a result of the change in corporate income tax rates, the trust recorded a future income tax recovery of $3.3 million in 2003.

The provision for future income taxes is different from the amount computed by applying the combined statutory Canadian Federal and Provincial income tax rate to income for the period before income taxes.

The differences are as follows:

	2003		2002
Income before income and other taxes	**40,880,035**	$	27,929,825
Statutory combined federal and provincial income tax rate	**40.98%**		42.22%
Expected income tax expense at statutory rates	**16,752,638**	$	11,791,972
Add (deduct) the income tax effect of:			
Non-deductible crown charges	**10,659,788**		9,281,286
Resource allowance	**(9,077,768)**		(7,785,742)
Alberta royalty tax credit	**(117,822)**		(165,552)
Reduction in corporate tax rate	**(3,250,000)**		(399,161)
Income attributable to the Trust, not subject to income tax	**(16,259,305)**		(4,685,229)
Capital tax	**879,340**		911,102
Other	**(179,148)**		(224,092)
Income and other taxes	**(592,277)**	$	8,724,584

The components of the future tax liability at December 31 are as follows:

		2003		2002
Capital assets in excess of tax value	$	**47,164,042**	$	49,126,298
Provision for site restoration and abandonment		**(1,136,401)**		(934,438)
Non-capital losses		**(2,662,030)**		(3,868,656)
Other		**(1,548,768)**		(1,689,718)
Future income taxes	$	**41,816,843**	$	42,633,486

As at December 31, 2003, the Trust had non-capital losses for income tax purposes of approximately $7 million which expire in 2009.

14. RELATED PARTY TRANSACTIONS

a) The Trust has three directors who are also directors of Storm Energy Ltd., a publicly listed oil and gas company. There are accounts receivable and accounts payable with Storm Energy Ltd. arising through the normal course of business and measured at the exchange amount which is the amount of consideration established and agreed to by the related parties. The Trust had approximately $1.8 million (2002 - $9.4 million) due to Storm Energy Ltd. and $1.0 million (2002 - $10.5 million) due from a subsidiary of Storm Energy Ltd. at December 31, 2003.

b) During 2003, the Trust paid $97,730 for legal services (2002 - $114,000) provided by a firm in which a current director is a partner.

c) In June 2003 the Trust completed the Loon Lake property acquisition for $17.4 million from Storm Energy Ltd. The approval of the transaction was made by the unrelated directors of the Trust based on an independent engineering evaluation.

15. COMMITMENTS AND CONTINGENCIES

The Trust is involved in litigation and claims arising in the normal course of operations. Management is of the opinion that any resulting settlements would not materially affect the Trust's financial position or reported results in operations.

16. SUBSEQUENT EVENTS

On April 1, 2004 the Trust expects to complete the acquisition of additional working interests at its Tommy Lakes property in northeastern British Columbia for $110 million before closing adjustments. The acquisition was financed with a combination of debt drawn from the Trusts existing credit facilities and a bought-deal equity financing of $74.5 million.

The Trust issued 5,000,000 Trust Units at $14.90 per unit to raise gross proceeds of $74.5 million on March 23, 2004 to partially finance the above described acquisition.

Quarterly Information

(thousands of dollars, except where indicated)	2003 Q4	2003 Q3	2003 Q2	2003 Q1	2002 Q4	2002 Q3 (1) 39 Days
FINANCIAL						
Oil and gas revenues, before royalties	26,732	26,740	29,863	28,498	24,423	8,908
Funds flow from operations	17,129	15,200	16,764	16,715	14,184	4,818
Per unit – basic	$ 0.54	$ 0.48	$ 0.57	$ 0.57	$ 0.49	$ 0.17
Cash distributions per Trust Unit	$ 0.42	$ 0.42	$ 0.42	$ 0.41	$ 0.33	$ 0.11
Payout ratio – per Unit basis	78%	87%	74%	71%	68%	66%
Net income	10,456	10,608	12,449	7,960	8,738	1,422
Per unit – basic	$ 0.33	$ 0.34	$ 0.42	$ 0.27	$ 0.30	$ 0.05
Capital expenditures	4,750	2,796	50	9,214	3,666	481
Acquisitions, net of proceeds on disposition	142	13	20,062	–	605	–
Long-term debt plus working capital	23,611	23,650	27,545	38,767	36,534	38,076
Per unit – basic	$ 0.74	$ 0.75	$ 0.87	$ 1.33	$ 1.26	$ 1.33
Times funds flow from operations (2)	0.3	0.4	0.4	0.6	0.6	0.8
Total Trust Units – outstanding (000's)	31,822	31,667	31,493	29,180	28,966	28,736
Weighted average Total Trust Units outstanding (000's)	31,759	31,631	29,458	29,106	29,106	28,605
OPERATIONS						
Average daily production						
Crude oil (bbls/d)	2,278	2,336	2,361	2,444	2,469	2,608
NGLs (bbls/d)	460	508	501	471	464	441
Natural gas (mcf/d)	32,476	33,593	36,815	34,158	32,911	26,101
Barrels of oil equivalent (BOE/d @ 6:1)	8,151	8,443	8,997	8,608	8,419	7,400
Weighting to natural gas	66%	66%	68%	66%	65%	59%
Product prices realized (incl. hedging settlements)						
Crude oil ($CDN/bbl)	$ 37.20	$ 39.07	$ 40.64	$ 45.84	$ 37.90	$ 38.83
NGLs ($CDN/bbl)	$ 29.66	$ 34.18	$ 30.78	$ 42.59	$ 35.70	$ 33.80
Natural gas ($CDN/mcf)	$ 5.78	$ 4.97	$ 5.60	$ 5.83	$ 4.83	$ 3.89
Netback per BOE						
Revenue (incl. hedging settlements)	$ 35.15	$ 32.67	$ 35.32	$ 38.50	$ 31.96	$ 29.41
Royalties, net of ARTC	(8.48)	(8.63)	(9.65)	(12.31)	(8.52)	(7.41)
Production expenses	(3.70)	(3.51)	(3.04)	(3.36)	(3.05)	(3.19)
Netback per BOE	$ 22.97	$ 20.53	$ 22.63	$ 22.83	$ 20.40	$ 18.81
Funds flow from operations per BOE	$ 22.84	$ 19.57	$ 20.48	$ 21.57	$ 18.31	$ 16.70
Wells drilled (gross)	10	4	–	9	7	–
TRUST UNIT TRADING STATISTICS						
Unit prices (based on daily closing price)						
High	$ 15.30	$ 14.50	$ 12.85	$ 11.74	$ 10.50	$ 9.10
Low	$ 13.25	$ 11.95	$ 10.80	$ 10.05	$ 8.85	$ 10.65
Close	$ 15.00	$ 13.46	$ 12.09	$ 11.30	$ 10.15	$ 10.63
Daily average trading volume	74,437	85,641	81,199	110,116	108,098	160,462

(1) The above information only includes operations of Focus Energy Trust which commenced operations on August 23, 2002 as per the Plan of Arrangement

(2) Long-term debt plus working capital divided by funds flow from operations for the quarter

Corporate Information

SENIOR MANAGEMENT

Derek W. Evans
President and C.E.O.

William D. Ostlund
Vice President, Finance and C.F.O.

Dennis M. Lawrence
Vice President, Engineering

Bryce H. Murdoch
Vice President, Geology

Al S. Pickering
Vice President, Land

David W. Sakal
Vice President, Operations

A. Kim Schoenroth
Controller

Grant A. Zawalsky
Corporate Secretary

DIRECTORS

Matthew J. Brister (3) (4) (5)
John A. Brussa (3)
Stuart G. Clark (1) (2)
Derek W. Evans
James H.McKelvie (2) (3)
Gerry A. Romanzin (2) (4) (5)

(1) Chairman of the Board
(2) Member of the Audit Committee
(3) Member of the Compensation Committee
(4) Member of the Reserves Committee
(5) Member of the Corporate Governance Committee

HEAD OFFICE

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STOCK EXCHANGE LISTING

TSX Listings:
Focus Energy Trust: **FET.UN**

FET Resources Ltd.: **FTX**
(Exchangeable Shares)

SOLICITORS

Burnet, Duckworth & Palmer LLP
Calgary, Alberta

AUDITORS

KPMG LLP
Calgary, Alberta

BANKERS

Bank Syndicate
Lead Agent: Royal Bank of Canada
Calgary, Alberta

ENGINEERING CONSULTANTS

Paddock Lindstrom & Associates Ltd.
Calgary, Alberta

McDaniel and Associates
Consultants Ltd.
Calgary, Alberta

REGISTRAR & TRANSFER AGENT

Valiant Trust Company
Calgary, Alberta

ABBREVIATIONS

API	American Petroleum Institute
ARTC	Alberta Royalty Tax Credit
Bcf	Billions of cubic feet
Bcfe	Billions of cubic feet equivalent
BOE	Barrels of oil equivalent @ 6:1
BOE/d	Barrels of oil equivalent per day
bbl	Barrel of oil or natural gas liquids
bbls	Barrels of oil or natural gas liquids
bbls/d	Barrels per day
$CDN	Canadian Dollar
GJ	Gigajoules
GJ/d	Gigajoules per day
Mmbtu	Millions of British Thermal Units
Mmbtu/d	Millions of British Thermal Units per day
mbbl	Thousand barrels
mbbls	Thousands of barrels
Mmbbls	Millions of barrels
Mmcfe/d	Millions of cubic feet equivalent per day
Mboe	Thousands of barrels of oil equivalent
Mboe/d	Thousands of barrels of oil equivalent per day
Mmboe	Millions of barrels of oil equivalent
mcf	Thousands of cubic feet
mcf/d	Thousands of cubic feet per day
Mmcf	Millions of cubic feet
Mmcf/d	Millions of cubic feet per day
Mw	Megawatt
Mw/hr	Megawatt per hour
NGL	Natural gas liquids
OPEC	Organization of Petroleum Exporting Countries
RLI	Reserve Life Index
TSX	Toronto Stock Exchange
WTI	West Texas Intermediate
$US	Unites States dollar

FOR FURTHER INFORMATION CONTACT:

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